U.S. ELECTRIC POWER SYSTEM RELIABILITY

HEARINGS

BEFORE THE

SUBCOMMITTEE ON
ENERGY DEVELOPMENT AND APPLICATIONS

AND THE

SUBCOMMITTEE ON
ENERGY RESEARCH AND PRODUCTION

OF THE

COMMITTEE ON
SCIENCE AND TECHNOLOGY
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U.S. ELECTRIC POWER SYSTEM RELIABILITY

TUESDAY, JUNE 8, 1982

House of Representatives, Committee on Science and Technology, Subcommittee on Energy Development and Applications, and the Subcommittee on Energy Research and Production,

Washington, D.C.

The subcommittees met, pursuant to call, at 9:30 a.m., in room 2325, Rayburn House Office Building, Hon. Marilyn Lloyd Bouquard (chairman of the Subcommittee on Energy Research and Production) presiding.

Present: Representatives Bouquard, Schneider, Volkmer, and Skeen.

Mrs. **Bouquard**. The subcommittee will come to order.

Good morning, ladies and gentlemen.

There is general agreement that the U.S. electric utility industry has attained a level of reliability unmatched in most other countries. However, events of the past decade have created uncertainties in our continuing ability to preserve this highly reliable electric service.

Several forces appear to be converging in a manner which can adversely affect the electric utility industry. We are here today in an effort to separate fact from fiction so that the committee can be better prepared to determine priorities for future legislation that will pertain to electric energy supply, transmission, and distribution systems.

The events of the past 8 years have taught us that we cannot be complacent. Convulsions in foreign oil supply and price impact electric energy production and use. Public apathy toward nuclear power production limits long-range planning for its use. The lack of firm environmental standards for the use of coal jeopardizes projections for new powerplant construction. The aging of powerplant and distribution networks indicate a potential decline in reliability. The age of rebellion, and particularly terrorism, offers opportunity for disruption of electric systems. These conditions make electric power management a horrendous task.

My Subcommittee on Energy Research and Production has authorization and oversight responsibility for the electric energy systems program, energy storage program, the nuclear fission program and the fusion energy program. I am therefore most concerned that in the future, and in particular in the long term, that we preserve and improve the reliability of electric service for industrial, commercial, and private applications.

Current trends in substituting heat pumps for oil-fired heaters surely confirm the need for reliable electric power. I am convinced that we must lean toward the greater use of electric power, not away from it, for there are precious few alternatives. In transportation, we are making progress toward the development of a high-power density battery which, if successful, could result in a dramatic shift to electric power.

We are not going to experience zero growth in the future despite current economic conditions. My friends in the utilities industry project 3- to 4-percent growth in future electric power demand. At 3 percent, the requirements for electric power would double in 25 years.

In this hearing, then, we seek not only a factual perspective of the status and the outlook for electric power reliability but a dialog with industry. We welcome a mutually beneficial assessment of needs and priorities.

This morning we have two panels of distinguished individuals representing a cross-section of viewpoints. Their comments on the subject of power system reliability will be most appreciated.

As our first panel, we welcome Kurt Yeager, director, coal combustion systems division, Electric Power Research Institute; Walter P. Schultheis, vice president, power supply and research, Northeast Utilities; and David Fogarty, senior vice president of Southern California Edison.

Good morning, gentlemen. I certainly look forward to your testimony.

STATEMENTS OF KURT YEAGER, DIRECTOR, COAL COMBUSTION SYSTEMS DIVISION, ELECTRIC POWER RESEARCH INSTITUTE; WALTER P. SCHULTHEIS, VICE PRESIDENT, POWER SUPPLY PLANNING AND RESEARCH, NORTHEAST UTILITIES, INC.; AND DAVID J. FOGARTY, SENIOR VICE PRESIDENT, SOUTHERN CALIFORNIA EDISON

Mr. **Yeager**. Thank you, Madam Chairman and members of the subcommittees. I am Kurt Yeager, director of the coal combustion systems division of the Electric Power Research Institute in Palo Alto, Calif., and I appreciate this invitation to meet with you to discuss technology development efforts for electric power system reliability and productivity.

Emphasis on near-term productivity-related research and development has been increased to nearly 70 percent of the total EPRI budget. In doing so, the EPRI strategy places highest priority on programs that achieve the most effective operation and the highest possible availability of existing fossil and nuclear powerplants.

My comments today will focus on joint EPRI utility developments for improving the reliability and productivity of fossil fuel generating units, particularly coal. These activities can be organized into six basic categories.

First, identifying and determining the root cause of the failures that do occur in the industry; second, understanding the relationship between fuel quality and performance and reliability of powerplants. Third, design, operation and maintenance improvements for powerplants. Fourth, diagnostic instrumentation. Fifth, environmental control improvements and sixth, efficiency improvements.

These ongoing activities alone are designed to produce savings of several billion dollars a year for our industry. Results last year alone in terms of the initial demonstration of results going from this program were over $50 million to the first utilities who participated in these demonstrations.

Several factors contribute to the reliability limitations experienced by powerplants and these have included declining fuel quality, the requirement for plants to operate outside of their design because of load requirements, the reduced engineering design margins results from minimization of first costs within the powerplants, increasing auxiliary environmental control requirements and last the underlying, inadequate return on equity combined with rapidly increasing costs to the industry.

Problems of wide concern in this area are recognized from the statistics compiled by the North American Electric Reliability Council—NERC—and these form the bases for ours as well as individual utilities' efforts to improve reliability.

The first necessary step in the use of this kind of information in resolving a reliability problem is understanding the basic or root cause of the problem. It isn't enough to say it hurts. We have to understand why and where it hurts and what to do about it. As a result of that, we have cosponsored with individual utilities a number of root cause projects designed to identify the generic issues in major plant components that adversely affect the reliability of the powerplant.

I think it is important to perhaps touch on several of the basic elements in this formal approach which have been developed with the industry.

First, is development of an information base to provide the data necessary to conduct root cause analyses of equipment failures. This requires a synergistic approach with individual utilities in which they largely are the developers of the information.

Second, is the use of a formal procedure for isolating the root cause of a problem.

Third, is formation of a skilled investigative team consisting of an appropriate mix of technical disciplines and management support leading to formal presentation of the results of the root cause analyses to the industry for their implementation of the recommended corrective actions.

The results provide not only guidance for research and development but more importantly, direct immediate application by the industry to assure that the operation and maintenance of the powerplant equipment is within the limits which will avoid failure or loss of operating time.

The second element of the program I will touch on is the relationship between coal quality and plant performance and reliability.

Recent trends in reliability and efficiency of powerplants has led to a reexamination by the industry of the entire power generating system from coal supply to ash disposal. The sensitivity of pulverized coal powerplants which are the backbone of our industry, to coal quality has particularly emerged as a major industry concern.

In resolving this concern, the U.S. utility industry has learned that improved coal quality can pay economic benefits and the cheapest coal does not necessarily produce the lowest cost electricity.

Several serious investigations of the effect of coal quality on plant performance and operating costs have recently been completed by individual utilities as well as under Department of Energy sponsorship. Although site-specific trends must be individually defined, they all indicate one common factor and that is the relationship between coal quality and reliability of powerplants.

As a result, the Electric Power Research Institute —EPRI—is expanding its efforts to formulate guidelines which upon implementation will provide the utilities with the economic quantification of the effects of coal quality on their existing powerplants so that they can make the determination of how much is improvement in coal quality worth in terms of reliability and performance and what should they do about it?

In addition, we have also developed a real-time and continuous coal quality analysis technique called, "CONAC" which permits plant operations to be optimally tuned to changing coal conditions. This technique is being initially applied by Detroit-Edison and the Tennessee Valley Authority.

Moving now to the powerplant itself, the various statistical losses which occur within the plant are generally identified by the NERC data. These losses are categorized by cost code and modified by the operational experience collected by the utilities and their suppliers. This produces a priority of outages that forms the basis upon which we develop our research program.

In the interests of time, I would not propose to review each element of that research program in detail. It is in my written material and is available to the committee.

Mrs. BOUQUARD. Your entire statement will be made a part of the record and you may summarize as you wish.

Mr. YEAGER. Thank you very much.

Moving to the third topic, no discussion of powerplant reliability impacts would be complete without considering environmental control. It is particularly important because although its impact is not trivial today, its greatest impact is probably yet to come.

Over the past decade, the growth of environmental control regulations has had a major effect on the operation of coal-fired powerplants. Before 1970, about 10 percent of the powerplant investment was directed to environmental control. Today that has increased to 40 percent of the total cost of a new plant and represents the largest single cost element in a new coal-fired powerplant.

Typically, the greatest reliability risk is the flue gas desulfurization system, particularly for use with high sulfur coal. As a result, the National Academy of Sciences has recommended giving highest priority to improving the reliability of flue gas to sulfurization scrubber systems for this high sulfur application.

The average reliability, for example, of scrubbers in the 1974 to 1981 period was about 80 percent, with many units well below that level. Now, this average is well below an acceptable minimum for powerplant component reliability. If every part we had in the powerplant only operated at 80 percent reliability, the product of all of those individual components would lead us to zero power production.

Mrs. BOUQUARD. What is the major problem with the scrubbers?

Mr. YEAGER. The major problem with the scrubbers has largely been a matter of inexperience on the part of both suppliers and users in the technology and its premature application under conditions for which it was really never initially intended. That is one aspect of technology forcing that leads to major reliability limitations. It is being slowly overcome but is an extremely painful and very expensive process.

Mrs. BOUQUARD. That is a mighty specific requirement to acquire a better track record.

Mr. YEAGER. As a first step, there is an obvious need for a much more systematic approach to improving reliability in the industry and clearly, again, the regulations have not provided much of a positive incentive for this. There has been a good deal more stick than carrot, if you will, in the use of environmental control technology. While it is most dramatic in the area of flue gas desulfurization, it is not unique to that technology.

Particulate control, nitrogen oxide control, waste disposal are all elements of this overall picture which combine as a very new, major and unplanned impact on the industry.

The objective should be how do we best achieve the necessary balance between the primary job of producing power most reliably and the needs of the environment. Our adversarial process tends to impede, not promote this objective.

Fortunately, the ground work for this kind of improvement I believe is now being laid. Some of the advancements include development of a new industry flue gas desulfurization component failure data system which allows us for the first time to deal with an objective root cause analysis of the problems in this area.

Better control of process chemistry in flue gas desulfurization is also decodified—we are getting to know much more about the implication of a highly variable material; coal, which is the feedstock for this chemical process.

Development of new systems have promised fewer problems in reliability through simplicity and, of course, through an improved working knowledge of proper construction materials, since erosion and corrosion have been major limiting factors.

I would now like to turn for a moment to powerplant efficiency, because I think it is unrealistic to discuss reliability without having discussed efficiency. I think they go hand in hand.

During the past decade, powerplant efficiency has also decreased. We believe it is important to reverse this trend, and have carried out a 2-year study on design of fossil fuel powerplants. As a result, improvement in heat rate appears possible in both new and existing plants. We believe this can be achieved with an associated improvement in reliability. The trend in unit availability and capacity factors suggests that reserve margins will continue to be a concern of the future. That indicates that the maximum power possible will be required from our existing fossil plants, particularly during peak periods, and an improved heat rate will be one factor which will assist in improving system reserve margins.

Unfortunately, traditional thinking has suggested that plant efficiency and reliability are fundamentally in conflict. Our examination of the experience in the industry, however, indicates there is no statistically significant difference between our newer, high efficiency and older, low efficient plants in terms of reliability.

Furthermore, we can find nothing inherent in the design of the new, higher efficiency supercritical powerplants that will contribute to lower reliability. In fact, for plants in the large 600- to 800-megawatt range, with supercritical pressure and double reheat conditions, average availabilities of over 80 percent have been maintained in recent years.

I might comment that this advantage is underscored by the rapid progress in coal-fired power generation technology which is now being made overseas, particularly in Japan, where nothing but supercritical powerplants are being constructed.

As we move into a new area with greatly expanded needs for coal power generation, EPRI and the utility industry are also accelerating development and application of alternate methods of concurrently achieving both high efficiency and reliability. Especially important among these is fluidized bed combustion as a further evolutionary improvement in coal utilization to meet the new requirements; environmental, fuel, reliability, and efficiency which face our industry. As such, we believe it offers substantially greater growth potential for improvement in performance and cost than pulverized coal technology.

Industry is also very active in coal conversion technology that I think you will be hearing more about from other experts.

In summary, I believe our powerplants of all types will, in the future, reflect this new emphasis on combining plant reliability, efficiency, and longevity. One of the first likely impacts will be the introduction of online performance and monitoring systems on more fossil plants.

The data from these systems will be used for pinpointing deteriorating components before they fail to avoid the very expensive unplanned forced outages as well as determining areas of efficiency loss so that we can get the most from our powerplants.

In this regard, one area that is getting particular attention from the utilities is the updating and expanding of the training and skills of station personnel assigned to monitor and maintain reliability and efficiency.

Extension of the life of existing plants will also encourage the addition of retrofit measures to improve heat rate and reliability. As components in these aging plants are changed out, replacements will be selected with optimized efficiency and reliability in mind, both in terms of design changes and in component operation.

To maintain the reliability, the use of online diagnostic monitoring tools will become more prevalent. I think this is one of the most important areas for improvement in the availability of our powerplants. These predictive maintenance systems will be able to anticipate failures, allowing plant personnel to schedule outages, order spare parts, and provide manpower in an optimal fashion.

Along with the diagnostic systems will come a further change in control room practices, as the additional diagnostic information is fed to suitable display devices.

I would comment here that a number of individual utilities as well as utility industrywide groups are very active in developing the protocols for the use of this kind of technology within the powerplants.

In conclusion, I would say that it seems highly probable that the very special characteristics of electricity, for example, its focused application, its almost unique ability to use our most available domestic fuel—coal, its ease and precision of control, its transportability, and availability, uniquely qualify it for expanded application in the future.

In other words, to achieve this expanded application in the economic realities of today, improving powerplant productivity and reliability is a priority issue for all utility managers and one having very substantial benefits for the consumer. In achieving this objective, the EPRI is working closely with the industry and its suppliers to provide the methods and technology for improving reliability of powerplants.

In short, there is no shortage of opportunities to improve the performance of our power generation system. Fundamental to the successful implementation of these opportunities requires, however, is a more constructive partnership between the government at all levels and the private sector.

Key elements in this partnership must include: insuring the financial health of the regulated electric utility industry so that improvements can be implemented and second, eliminating the ratcheting of environmental control requirements without regard to the cost or probability of success of such steps, third, a consistent energy policy encouraging use of domestic energy resources and lastly, a storage partnership between government and manufacturers so that they can compete more effectively with the foreign partnerships in both foreign and domestic markets.

Thank you again for this opportunity, and I will be pleased at the present time to answer your questions.

[The prepared statement of Mr. Yeager follows:]

TECHNOLOGY DEVELOPMENT
FOR
ELECTRIC POWER SYSTEM PRODUCTIVITY

Statement of

Kurt E. Yeager, Director

Coal Combustion Systems Division

Electric Power Research Institute

Palo Alto, California

Before the

Subcommittee on Energy Development and Applications

Subcommittee on Energy Research and Production

June 8, 1982

INTRODUCTORY STATEMENT - Mr. Chairman, Members of the Subcommittees: I am Kurt E. Yeager, Director of the Coal Combustion Systems Division of the Electric Power Research Institute (EPRI). I appreciate this invitation to meet with you to discuss the technology development efforts of EPRI for electric power system productivity.

The EPRI was established by the electric utility industry in 1973 to plan and manage a comprehensive research, development and demonstration program for the entire electric utility industry and its rate payers. EPRI is supported by voluntary contributions from investor-owned, government and cooperatively owned electric utilities across the nation. Our 1982 budget calls for research expenditures of $250 million.

Emphasis on near-term productivity R&D, endeavoring to produce results within the coming decade has been increased to 69% of total EPRI spending. In doing so EPRI's R&D strategy places highest priority on programs that:(1)

- Achieve more effective operation and higher availability on existing fossil and nuclear plants.
- Extend the life of existing generating units, transmission facilities, and distribution systems.
- Develop less costly and more efficient new production and delivering technology.

My testimony today will focus primarily on EPRI/utility developments for improving the productivity of fossil-fueled generating units, particularly coal. These developments will encompass fuel quality and environmental control as well as the power plant itself and will consider reliability, efficiency and longevity as elements of productivity. Table 1 summarizes some of the recent results being applied by the utility industry. A list of EPRI publications addressing these developments is also attached.

THE CHALLENGE

The ultimate goal of an electric utility has previously been to provide reliability power to its customers at the lowest possible cost. Over the past decade new, almost revolutionary constraints have reshaped the technical requirements of the utility industry in general, and its approach to coal utilization in particular. In the 1970's, the emergence of increasing electrical rates, restrictive environmental control requirements, uncertainty over petroleum availability and skyrocketing fuel costs led the industry to consider a variety of new generating options. As we enter the 1980's, these new constraints have been joined by declining demand growth rates, restricted capital investment capability, loss of public confidence in the nuclear initiative, withdrawal of government funding support for technology development, and increased emphasis by domestic suppliers on the international market.

How the U.S. utility industry and its suppliers respond in this decade to these constraints will have important consequences for the power generation capability and structure into the next century Several considerations in the response seem clear:

- New generation capacity this century will depend increasingly on direct coal combustion.
- Priority will be placed on improving the reliability and longevity of generating coal capacity.
- Private sector responsibility for technology improvements will encourage lower risk, nearer term options. Criteria being stressed include:
    - improved reliability
    - less sensitivity to fuel quality
    - reduced field erection requirements
    - minimum auxiliary environmental equipment
    - reduced cost sensitivity to size
    - improved siteability
    - simplicity and operability
- U.S. supplier priority is likely to focus on adapting domestic experience to the competitive challenge of the international market.
- The U.S. utility user must assume greater leadership for the selection, development, and commercialization of improved and new technology.

One of the most pressing elements of this response is improvement in both availability and efficiency of power plants in general, and coal-fired power plants in particular. If a large baseload unit is unavailable, replacement power is probably being generated by oil: at current oil prices, a one percent loss in availability on a 500 MW(e) coal unit costs over $1 million per year. This compares with about $50,000 in 1970. By 1985 the industry-wide cost savings of a 1% improvement in availability on fossil fueled power plants alone is estimated at more than $1 billion. Several factors contribute to the reliability limitations experienced by power plants. These include:(2)

- declining fuel quality
- load-following by plants designed for baseload operation
- increased plant size and complexity
- reduced engineering design margins to reduce first cost
- increased auxiliary environmental control requirements
- inadequate return on equity and rapidly increasing costs.

Figure 1 indicates some of the technical opportunities which are being addressed by the industry to improve the productivity of this installed capacity. Figure 2 summarizes the general process followed to identify, define, rank, and address significant utility problems. Problems of wide concern often are recognized from the statistics compiled by the EEI and the NERC. These sources, however, generally do not define problem causes or establish research requirements. That is accomplished by EPRI advisory committees and staff, who work to define research projects.

ROOT-CAUSE ANALYSIS

The necessary first step in resolving a reliability problem is understanding its basic or root cause. EPRI has in place a number of root cause projects designed to identify generic problems in major plant components that adversely influence plant availability. The purpose of the root cause methods development project is to develop, qualify, and document methods of root cause analysis through cooperative efforts with utilities in the solution of problems of direct and immediate interest to utilities. Ultimate responsibility for the root cause of all failures may be identified as having human origin.

However, in pursuing solutions to power plant problems, the focus is on identifying the correctable cause of failure.

The basic elements of this formal approach are:

- Development of an information base to provide the data necessary to conduct root cause analyses of equipment failures. Key features of this information base are a data system for storing certain root cause and reliability information, systematic documentation of equipment design and analysis results, records from on-line monitoring systems, formal reports of on-site investigations of the cause of failures, and results of detailed testing and analysis of failure evidence.
- Use of a formal procedure for isolating the root cause of a problem. This procedure takes a logic diagram approach and aids in problem investigation as well as display of the analytical process.
- Formation of a skilled investigative team consisting of the appropriate mix of technical disciplines and management support. A task force approach is used for this team, with assignment of a responsible individual to assemble and manage the task force.
- Formal presentation of the results of the root cause analysis and recommended corrective actions. This assures that the results are retained in an accessible form and are available to interested utilities. It also facilitates verification of results.

The results provide not only guidance for R&D but direct and immediate application by utilities to assure that the operation and maintenance of power plant equipment is within the limits which avoid failure.

COAL QUALITY IMPROVEMENT(3)

The recent decline in plant reliability and efficiency has led to a reexamination of the entire power generating system from coal supply to ash disposal. The sensitivity of pulverized coal-fired power plant performance and reliability to coal quality has particularly emerged as a major industry concern. The operating experience of the recent past is being more carefully analyzed to guide future coal utilization decisions.

Considerations that are essential in the process of making prudent decisions on this subject are:

- Understanding the quality and variability of coal likely to be used over the life of the power plant.
- Evaluating the effect of coal quality on power plant design and capital cost.
- Evaluating the effect of coal quality on plant performance and availability.
- Establishing appropriate coal quality specifications.

In applying these considerations, the U.S. electric utility industry has learned that improved coal quality control can pay important economic dividends, and the cheapest coal does not necessarily produce the lowest cost electricity.

Several serious investigations of the effect of coal quality (ash concentration, ash composition, sulfur concentration, grindability, etc.) on power plant performance and operating cost have recently been completed. Initial results of the most comprehensive investigation, sponsored by DOE and encompassing the TVA system, indicates that for TVA conditions: (1) steam generator efficiency increases with a decrease in coal ash, (2) unit peak capacity increases with a decrease in coal ash, (3) unit availability increases 1.2 percent for each percent decrease in coal ash, (4) maintenance cost varies from $0.05 to $0.10 per ton of coal for each percent variation in coal ash, and (5) maintenance cost varies from $0.30 - $0.50 per ton of coal for each percent variation in coal sulfur.

Other investigations, particularly those of Utah Power & Light, Pennsylvania Electric Company, and American Electric Power, indicate similar benefits for firing of improved quality coal in existing power plants. EPRI is expanding these efforts to formulate guidelines which, upon implementation, will provide the utilities with economic quantification of the effects of coal quality on the performance and reliability of existing utility coal-fired power plants. Specific coal quality characteristics that will be investigated include: mineral matter (ash) concentration and composition, slagging and fouling characteristics, sulfur concentration and forms, moisture concentration, ultimate composition, heating value, and grinding characteristics. Power plant performance parameters will include: heat rate, efficiency, availability, capacity reliability, auxiliaries electricity consumption, slagging, fouling, erosion, corrosion, electrostatic precipitator performance, flue gas desulfurization system performance, flue gas reheat system performance, operating costs, and maintenance costs.

Based on these results, EPRI performs research, development and demonstration in the areas of coal cleaning, moisture reduction, handling, instrumentation, and control systems with various utilities. This program involves an EPRI commitment of more than $6 million a year plus significant cofunding by individual utilities, and others. A focal point for this program is the EPRI Coal Cleaning Test Facility (CCTF) located near Homer City, Pennsylvania. Built entirely with private funds at a cost of $14 million, this is the world's newest and most advanced coal cleaning test facility. Based on commercial scale equipment, the CCTF is demonstration scale with a maximum coal handling rate of 20 tons per hour. Unlike other test facilities, it is not dedicated to a single cleaning process but can accommodate a variety of projects resulting from EPRI research as well as others in the coal R&D community.

Cleaning operations currently being evaluated at the facility include heavy media cycloning, water only cycloning, tabling, and froth flotation. Fine coal and refuse dewatering can be accomplished by either centrifugation or filtration. Its flexibility permits simulation of more than 50 commercial cleaning plant system designs. The result: an appraisal of not only how well each unit operation performs individually but also how well it integrates with the rest of the plant. Major objectives of the CCTF include:

- Reducing coal losses in fine coal cleaning.
- Determining the cleaning characteristics of steam coal.
- Accelerating transfer of improved cleaning equipment to commercial application.
- Demonstrating improved coal sampling and analytical procedures.
- Developing and maintaining a utility oriented national coal quality data base.
- Providing training for coal preparation engineers and cleaning plant operators.

The CCTF is sponsored by EPRI; Pennsylvania Electric Company; New York State Electric and Gas Corporation; and the Empire State Electric Energy Research Corporation (ESEERCO). Participating utilities and coal suppliers will deliver run-of-mine samples of about 1000 tons to the CCTF for cleaning characterization. The results will provide the participating company with a reliable estimate of the commercial cleanability potential of the coal as well as verification of cleaning plant design and cost meeting its specific needs.

POWER PLANT ISSUES(4, 5)

The approximate statistical availability losses for each of the equipment areas of large fossil units (>600 MWe) are identified from industry data.

These statistical losses are then categorized by cause code and modified by experience.

In each case, the "general" category is more than 50% of the total outage causes. This provides further need for the root cause analysis effort discussed earlier. Omitting the "general" category of outage and utilizing the experience collected by utilities and suppliers produces the priority of outages shown below.

TOP PRIORITY OUTAGE CAUSES

Steam Generators

- Tube Failures
- Fouling, Slagging
- Control Failures

Turbine/Generators

- Blade Failures
- Bearing Failures
- Control Failures
- Rotor Failures

Plant Auxiliaries

- Boiler Feed Pumps
- Coal Pulverizers
- Fans
- Condensers

Steam Generators

This program focuses on four major problem areas:

- pressure part failures (tubes),
- fouling and slagging of fireside heat transfer surfaces,
- limitations of boiler control systems and cycling capabilities, and
- boiler performance improvements.

These account for most of the estimated equivalent availability loss on steam generators. The primary focus is on boiler tube failures, fouling and slagging, and improving boiler control and cycling capability.

The specific objectives of this program are to:

- Identify and eliminate major tube failure mechanisms through improved materials, fabrication and chemical treatment techniques and issuance of specification and quality assurance guidelines for pressurized components (1982-1985).
- Define the role of mineral-matter-in-coal on fireside slagging and fouling and develop improved design predictive methods, appropriate fuel additives and/or coal cleaning techniques to counteract or minimize the fouling/ slagging deposition processes (1982-1985).
- Develop operating guidelines for cyclic use of drum boilers by 1982 and once-through boilers (1983).
- Develop improved human factors design guidelines for boiler and related auxiliaries (1983).

Steam Turbines

This program concentrates on six major problem areas:

- Turbine blade failures
- Bearing failures
- Solid particle erosion problems
- Thermal performance testing methods
- Turbine materials improvement
- Maintainability and operability

The problem areas above account for over 80% of steam turbine availability loss. Since the technical products from this program entail the performance of near-term development work that will incrementally improve existing design, maintenance and operating practices, no significant technical barriers should be encountered.

The Rotating Electrical Machinery Program of the Electrical Systems Division and the Engineering and Operations Department of the Nuclear Power Division are performing projects that relate directly to this program's activities. These include: Torsional vibration monitoring, disc cracking, component monitoring and diagnostics and steam chemistry.

The specific objectives of this program are:

- Develop system for detecting water induction in steam turbines (1983).
- Develop methods of analyzing and reducing failures in low pressure turbine blading (1982-86).
- Identify bearing failure mechanisms and develop technology options to reduce failures in lubricating oil systems, bearing systems (1982-86).
- Develop techniques to reduce the susceptibility of turbine components to the effects of solid particle erosion (1982-86).
- Develop guidelines and technology options for cyclic operation to minimize mechanical damage while ensuring economic and flexible operation (1982-85).
- Validate improved, reduced cost methods of thermal performance testing (1982-86).
- Develop improved analysis techniques and improved materials for turbine rotors and blading (1982-86).
- Provide improved turbine maintenance methods (1983-86).

Plant Auxiliairies

This program is directed at improvements in the reliability of condensers, feedwater heaters, boiler feed pumps, fans, pulverizers, fuel/ash handling equipment, valves, etc. Current research focuses on: the vibrational behavior of rotating auxiliary machinery; the aerodynamic response of the steam generator air/gas system, including pulsation and implosion control; the rotorbearing dynamics and hydraulics of boiler feed pumps; the attenuation of noise, control of wheel/blade erosion, and structural dynamics of power plant fans; the control of condenser tube inlet-end erosion, mitigation of damage caused by high energy fluids, fouling caused by macro-organisms and debris, corrosion caused by dissimilar metals and polluted waters, and structural failures caused by poor design, fabrication, and installation practices, and; the prevention, detection, and control of coal pulverizer fires and explosions, as well as the reduction of material wear by abrasion and erosion.

The specific objectives of this program are to:

- Improve design analysis for vibrational tuning of foundations for rotating equipment (1982), and publish field-proven design guidelines (1983).
- Develop guidelines for reducing coal pulverizer failures (1982).
- Develop guidelines for reducing condenser outages (1982).
- Establish a facility to test reliability improvements in fossil plant valves (1985).
- Develop guidelines for reducing feedwater heater failures (1984).
- Develop guidelines for reducing air/gas system failures, including fans and air preheaters (1984).
- Improve methods for coal handling and storage (after 1985).

Plant Chemistry

This program provides support to the electric utility industry in matters related to power plant chemistry. Important goals are to: develop improved materials of construction, evaluate new chemical processes, provide operating guidelines for enhanced plant performance and reliability, and maintain liaison with utility industry committees.

Significant emphasis has been placed on the development of steam turbine rotor forgings and coatings for low pressure steam turbine blades. Model training curricula have been provided and manuals on water technology are now being written. Turbine manufacturer's steam purity recommendations are under review and new chemical instrumentation is being evaluated.

Major technical objectives of the program are:

- Validate turbine vendor's steam purity recommendations (1982).
- Construct a boiler water test rig for the evaluation of various water treatment scenarios (1982).
- Publish definitive texts on power plant component chemical cleaning and water technology (1982-83).
- Develop programs for the use of microprocessor techniques in power plant chemistry operations (1984).

Integrated Plant

This program focuses on transferring technological improvements to the utility industry through design recommendations, operating guidelines, and maintenance methodology and coordination. Additional responsibilities include data collection and characterization of overall plant performance.

The long-term goal is an advanced plant design with maximum reliability and efficiency. Dynamic and steady-state computer simulations are under development to provide design guidance to the utility industry with regard to cycle optimization and control. In addition, these simulations will provide excellent trouble shooting tools for existing plant operations.

The specific objectives of this program are to:

- Develop dynamic and steady-state computer simulations of fossil plant operation and components (1982).
- Complete failure cause analyses of turbine bearings (1982).
- Develop and verify human factors design guidelines characterizing an optional man/machine steam generating system (1984).

- Complete a series of availability studies on specific utility fossil plants (1984).
- Issue guidelines for improved plant operation and for optimum plant maintenance methods (1985).
- Provide design recommendations for large plant fans, condensers and coal pulverizers for improved reliability (1984).
- Improve plant heat rate by developing an optimized performance monitoring and plant instrumentation system (1986).
- Qualify materials and validate design modifications necessary to achieve a 10% improvement in new plant heat rate (1982-1988).

Plant Diagnostics(6)

This program is aimed at a reduction in forced and planned outages of fossil plants through diagnostic monitoring and nondestructive evaluation of plant components. The program covers all plant components: boilers, turbines, auxiliaries, and particularly is directed to those plant areas contributing significantly to plant unavailability through component failure or through excessive required maintenance.

Major technical objectives are:

- Develop a vibration signature analysis system for plant rotating equipment (1985).
- Introduce an acoustic emission monitoring system for tube leaks in boilers and feedwater heaters (1986).
- Develop an on-line crack detection system in turbines based both on acoustic emission technology and on eddy currents (1987).
- Develop acoustic sensing techniques for bearing failures and blade rubbing (1985).
- Introduce a boiler stress analyzer for optimum cycling behavior of fossil plants (1984).
- Produce guidelines for the optimum inspection and maintenance of plant components using non-destructive evaluation techniques (1985).

A wide variety of other on-line monitoring and diagnostic systems are also being developed under EPRI contracts. These include:

- Acoustic monitoring of nuclear safety and relief valves to detect both leakage and gross flow (RP1246)
- Laser-Doppler monitoring of turbine-generator shaft oscillations (RP1855)
- Optical fiber temperature sensing of "hot spots" in generators (RP970)
- Acoustic-Doppler detection of steam turbine blade vibrations (RP1854)
- Turbine water induction monitoring (RP637)
- Corrodent detection in steam turbines (RP1409)
- Eddy current detection of crack formation and growth in operating turbines (RP1957)

Although many of the techniques are in early stages of development, several others have already demonstrated their usefulness in detecting failures and helping utilities schedule their maintenance more effectively. Savings in outage times and repair costs have already amounted to millions of dollars. We expect even more profound effects on operating practices as utilities begin to rely on proven monitoring and diagnostic systems to plan and schedule their maintenance.

ENVIRONMENTAL CONTROL

Over the past decade the growth of environmental control regulations has had a major impact on the cost and operation of coal-fired power plants. Before 1970 about 10% of the cost of a new power plant was directed to environmental control. Today that has increased to typically 40% of the total and represents the largest single cost element of a new coal-fired power plant.(7)

Typically the greatest reliability risk is the flue gas desulfurization (FGD) system, particularly for use with high sulfur coal. As a result, the National Academy of Sciences has recommended giving highest priority to improving the reliability of FGD systems for this application.(8)

Today 94 FGD units representing a total controlled capacity of 36,000 MW(e) are operational on utility power plants. 70,000 MW(e) of additional FGD capacity are under construction or planned.(9) EPRI has and is continuing to invest about $25 million per year in improving the reliability of environmental control equipment with about $10 million per year directed to FGD systems.

Unfortunately, the first FGD plants were designed and constructed with little experimental data on smaller-scale plants because it was believed that FGD units could be constructed using the experience gained in other industries in which a particular constituent must be removed from a gas stream. Experience, however, has shown that a wide variety of unexpected problems were encountered. These included unexpected chemical reactions whose by-products had very low saturation levels, resulting in scaling and pluggage of scrubber internals; high mist loadings; higher than expected energy, water, and reagent consumption; and operating problems caused by the need for higher solids content in slurries than had been anticipated.

Utilities had little or no operating experience with chemical plants of this type and no knowledge about how such plants should be designed so that they could be integrated into the conventional equipment in an electric generating plant. Further, the regulatory process did not provide the positive incentive necessary to encourage success by either vendor or user.

Scrubber performance can be evaluated in terms of a performance index that considers SO_2 removal efficiency, process reliability, and plant load factor. The current federal New Source Performance Standards translate into a scrubber performance index of about 67%. The best performance index for an operating utility scrubber in this country is still less than 60%. As a result, flue gas desulfurization systems for a typical power plant are the least reliable link in the chain of power-generation equipment. Such a reputation is surely due in part to their being the newest equipment in power plants, and the technology supporting FGD has been forced to evolve quickly for a variety of reasons - rapidly changing regulations and the inexperience of power plant operators in contending with what amounts to a small chemical plant. While everyone in the industry has learned much about improving reliability of FGD, there are still formidable challenges in raising their standards to the levels of other power-generation equipment.(10)

Many improvements to date have resulted from choosing more exotic materials of construction to combat erosion and corrosion, or from complete sparing of absorber modules so that a full backup system is available should the first-line system malfunction.

There is an obvious need for a more systematic approach to reliability, which will benefit the entire industry. Fortunately, the groundwork for this is now being laid. Some of the advancements include development of a new EPRI FGD-component-failure data system, better control of process chemistry in FGD, development of new systems that promise fewer problems with reliability, and, of course, an improved working knowledge of the proper construction materials.

Although many indices are available to measure FGD reliability - typically based on time loss, energy loss, or emission-control loss - one useful index is the following: FGD reliability equals the time system operated divided by the time the system was called on to operate for any calendar interval. Using this measure, an EPA survey finds that the index for 1980 and 1981 has leveled off at 83.3% and 82.0%, respectively. The average for 1974-1981 is 80.9%, according to the same survey. This is well below an acceptable minimum for utility power plant component reliability.

EPRI compiled data on experience with the first generation FGD units - 15 units that came on line between 1972 and 1976. The major problems, which were mostly linked to poor process control of the throwaway mode of wet lime/limestone scrubbing, showed no correlation with manufacture, operating conditions, or year of initial startup. But the report did indicate a general mismatch between component design and materials of construction under the range of operating conditions encountered. Specifically, there were four primary factors responsible for low FGD reliability:

- Plugging, scaling, and corrosion of scrubber internals, mist eliminators, and reheaters.

- Need for open-loop operation-blowdown of scrubber liquor to reduce corrosive-substance concentration and dissolved-solids content.
- Corrosion and failure of stack liners.
- Plugging and failure of piping, pumps, and valves.

The National Academy of Sciences reached similar conclusions in their recent examination of FGD technology.(8)

In response to these issues of scrubber reliability, EPRI and the industry have set the following technical performance targets for FGD systems:

- Availability improved to >95% for high-sulfur coal.
- FGD processes or subsystems with a heat rate penalty below 300 Btu/kWh.
- Improved instrumentation, materials, and maintenance procedures to achieve 99% availability of the FGD system.
- Improved utilization of lime and limestone to 95% or more on conventional scrubbers.

The specific objectives of this program are as follows:

- Evaluate materials for cyclic reheat, and pilot test cyclic reheat on high-sulfur coal (1983, 1986).
- Couple a scrubber with a wet ESP or a fabric filter at EPRI's Arapahoe Integrated Emissions Control Pilot Plant (1983).
- Field test improved alloys and coatings (1983).
- Field test improved components to improve reliability (1984, 1986).
- Publish materials selection guidelines resulting from laboratory and field testing of corrosion and erosion in FGD environments (1984, 1986).
- Evaluate SO_2 analytical methods and instruments in the field (1983).

- Evaluate continuous emission monitors in field test (1984).

Similar programs are also being implemented by EPRI on reliability issues associated with particulate and NO_x control, water quality and waste management technology.

POWER PLANT EFFICIENCY(11)

The average station heat rate decreased continuously until the early 1960s. Subsequently, there was little incentive to continue the effort because of the expected increase in nuclear power generation for baseload application and the availability of relatively inexpensive fossil fuels, also, additional environmental restrictions required flue gas treatment which had a significant adverse effect on heat rate. A further negative impact resulted from the need to cycle many large fossil plants and run the units at other than baseload. This mode of operation typically results in lower component efficiencies and increased heat rate of the units.

EPRI believes that it is important to reverse this trend and has recently carried out a 2-year study on the design of fossil plants.(12,13) As a result, a substantial improvement in heat rate appears possible in new fossil plants. For existing units, EPRI is pursuing a program of on-line performance monitoring and improved instrumentation and testing. The cumulative effect of this effort on the close to 1000 fossil units currently in service, if a 1% heat rate improvement can be realized, will be a significant reduction in fuel usage as well as immediate economic benefits to the operating utilities.

The trend in unit availability and capacity factor, suggest that reserve margins will continue to be of concern in the future. This implies that, in certain areas of the country, the maximum power possible will be required from some fossil units during peak loads. Improved heat rate will be one factor which will assist in improving system reserve margins.

The evaluation of the benefits of higher steam conditions and innovative design concepts must include critical consideration of their impact on unit reliability. Traditional opinion has suggested that supercritical steam-electric plants cannot be expected to produce reliability levels equivalent to those of subcritical plants. Further, the fuel cost savings from high efficiency plants may be more than offset by their increased capital cost and reduced reliability. The EPRI studies concluded that this is unlikely. U.S. utility experience indicates there is now no statistically significant difference between once-through (supercritical) and drum-type (subcritical) unit reliability.(Figure 3) Furthermore, we find nothing inherent in the design of supercritical plants which should contribute to lower reliability. The total forced outage hours are about the same for once-through and drum units. Approximately 25% of the forced outages for each type are caused by waterwall and boiler tube failures. In the case of the once-through units, the boiler related causes account for 43% of the forced outages compared with 39% for the drum units, with the major difference in the economizer area. For the drum units, approximately 22% of the forced outages are accounted for by the turbine, compared with only 7% for once-through units. While on average the first large, supercritical power plants achieved poorer availability during the 1960's, the plants built in the 1970's demonstrated superior results to drum units. In fact, for plants in the 600 to 825 MW(e) range with supercritical pressure and double reheat, average availabilities over 80% have been maintained in recent years.

The electric utility industry is also aggressively evaluating and participating in the development of technologies which may ultimately provide for less costly and more reliable operation than current pulverized coal systems. These options are intended to carry utility coal utilization beyond the limits inherent in even advanced pulverized coal technology.(14)

This effort to move beyond these limits is driven by the issues of increasing environmental control with its associated cost and complexity, decreasing fuel quality, diminishing plant availability and siting limitations. Other considerations affecting the commercial selection of new coal combustion technology include load growth requirements, financing capabilities, and licensability, plus intangibles such as operational familiarity and supplier commitment. As a result, no single new technology can adequately meet the range of operating demands facing the U.S. electric utility industry.

Although the various advanced options offer potential improvements in environmental, cost and efficiency performance relative to current plants, the most important factor in their commercial acceptance will be their demonstrated capability to be at least as reliable as pulverized coal-fired power plants. Accordingly, power plant cycle development must place corresponding priority on reliability. This requires the construction and operation of large scale, engineering prototype or pioneer plants over a range of designs and fuels at operating conditions which are representative of the using utility industry.

As we move into a new era with greatly expanded needs for coal-fired power generation, EPRI and the utility industry are accelerating the development and application of fluidized bed combustion (FBC) as a further evolutionary improvement in coal utilization to meet these new requirements. As such it offers substantially greater growth potential for improvement in performance and cost than pulverized coal technology. The improvements which excite this utility interest include reduced sensitivity to fuel quality, thus permitting the use of a much broader fuel supply, from anthracite to municipal refuse, without suffering large losses in efficiency and reliability in a single boiler design. Second, less cost sensitivity to unit size; in a period when load growth and siting restriction may favor smaller rather than larger furnaces.

A third primary advantage of FBC that may lead to the displacement of pulverized coal boilers is environmental performance. The invention of pulverized coal boilers occurred at a time when all that was expected of a furnace was to burn out carbon. Today, environmental requirements for the control of sulfur and nitrogen oxides add substantially to the complexity and cost of current power plants and have adversely impacted plant reliability. By comparison, our experiments with fluidized combustion of coal confirm that it is possible to economically control sulfur and nitrogen oxides without parasitic postcombustion cleanup devices.

Thus, fluidized combustion of coal provides a promising response for today's new requirements on power production. Its advantages are also at least as relevant to the needs of the international utility market as those of the U.S. This is underscored by its demonstrated commercial acceptance in the world-wide industrial market. Development has successfully progressed from the process confirmation stage to engineering prototype making commercial utility scale systems possible this decade.

Our power plants will in the future, reflect this renewed emphasis on plant reliability, efficiency and longevity. One of the first impacts that will be seen, is likely to be the introduction of on-line performance monitoring systems on more fossil plants. This data will be used for pinpointing deteriorating components and areas of efficiency loss, as well as serving to optimize system dispatch procedures.

Along with this will come improved computer software with new trending and analysis algorithms. The impact of microprocessors will allow all stations to have adequate computing capability to handle this new demand, and at moderate cost. One area that utilities will need to address concerns the training and skills of station personnel assigned to monitor and update this capability.

New plant additions are likely to show a return to supercritical steam conditions with an emphasis on higher steam temperatures and pressures than currently employed. Stricter environmental legislation may penalize new plants even more from a heat rate viewpoint and will direct more attention to improved back-end designs and waste heat recovery devices.

Extension of the life of existing plants will encourage the addition of retrofit measure to improve heat rate, along with other component updates. As components in these aging plants are changed out, the replacements will be selected with optimized efficiency and reliability in mind, both in terms of design changes and in component operation.

To maintain the reliability of more advanced cycles and of new component designs, the use of on-line diagnostic monitoring tools will become more prevalent. These predictive maintenance systems will be able to anticipate the occurrence of failures, allowing plant personnel to schedule outages, order spare parts and provide manpower in an optimum fashion. Along with the diagnostic systems will come a further change in control room practices, as the additional diagnostic information is fed to suitable display devices.

SUMMARY AND CONCLUSIONS

Until the 1970s, it was popularly assumed that the expansion in energy use was strongly connected with growth in economic output and productive efficiency at work and at home. It was also widely accepted that the growth in per capita production of goods and services led to overall improvements in human welfare. But during the 1970s, untraditional ideas shook the implicit public consensus that supported both of these propositions.

The public perception of the role of electricity has fared badly in this period of pessimism. Electricity has been singled out for special criticism by some social critics of our industrial institutions. Unlike the other domestic energy industries that have benefited from government incentives to produce, the electric power industry until recently has been faced with many constraints and disincentives.

Yet, the longer term record of our national economy and social progress justifies a much different public attitude. Although the relationship between total energy and gross national product has been declining persistently in recent years--a highly publicized statistic--it is also the case that electricity growth continues to track GNP, as it has done rather consistently throughout the period since World War II.

It seems highly probable that the very special characteristics of electricity--its focused application, its ability to use domestically available fuel, its ease and precision of control, its transportability, availability, and wide range output--uniquely qualify it for expanded application in the future.

Electrofication of the industrial sector is picking up momentum in industrial nations, particularly France and Japan, and emerging nations such as Korea, Taiwan, Brazil, and India. National programs are being implemented with coal and nuclear plants because of domestic scarcities of petroleum. But even more importantly, these countries have recognized that the use of electrified processes can provide the basis for growth in overall economic efficiency. To produce products that compete worldwide, they have chosen to electrify.

In the United States, too, the continuing move to electrification is also evident. It is a logical policy because it reduces dependence on oil through the use of domestically abundant coal and uranium. It offers, in a very large number of applications, the most economically efficient power or energy form.

Against this backdrop, the unprecedented cost increases for fossil fuels and greatly increased lead times and costs for adding new generating capacity have made improving power plant productivity a priority issue for utility managers, and one having very substantial benefits for the consumer. Simultaneously, oil supply disruptions and the nation's dependence on oil imports have led to federal policies that set high priority on reducing oil and gas consumption by utilities. A major factor in reducing this consumption is improved productivity of coal generating units. Factors contributing to productivity limitations include:

- declining fuel quality
- emphasis on minimum first cost at the expense of life-time cost
- load-following by plants designed for baselad operation
- increased auxiliary environmental control requirements
- inadequate return on equity and rapidly increasing costs.

In helping overcome these productivity limitations, EPRI is working closely with the electric utility industry and its suppliers, to provide the methods and technology for improving the reliability and efficiency of the nation's power plants. These efforts also address the potential impact on availability caused by increasingly dominant environmental control requirements. Examples of recent accomplishments are attached.

The primary goal of the electric utility industry is to provide reliable power to its customers at the lowest possible cost. Although high availability is generally consistent with low cost, it is a valuable complement to, not a replacement for, new capacity in maintaining adequate generating reserve margins. It is, therefore, important that we remain alert to the continuing requirements for generating capacity and the opportunities for introducing new technology having inherently superior reliability, efficiency and environmental performance. EPRI and the utility industry are also aggressively developing and commercializing these options such as fluid bed combustion of coal and synthetic oil and gas from coal. It is through this constant "improving of the breed" that the electric utility industry keeps pace with the requirements it faces as the key ingredient in our goal of national energy self-sufficiency.

In short, there is no shortage of opportunities to improve the performance of our electric power generation system. The successful implementation of these opportunities requires, however, a constructive partnership between government at all levels, and the private sector. Key elements in this partnership must be insuring the financial health of the regulated electric utility industry and eliminating the ratcheting of environmental control requirements irrespective of their cost or probability of success.

Thank you again for this opportunity. I would be pleased to respond to your questions.

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Table 1

SUMMARY OF RECENT RESULTS

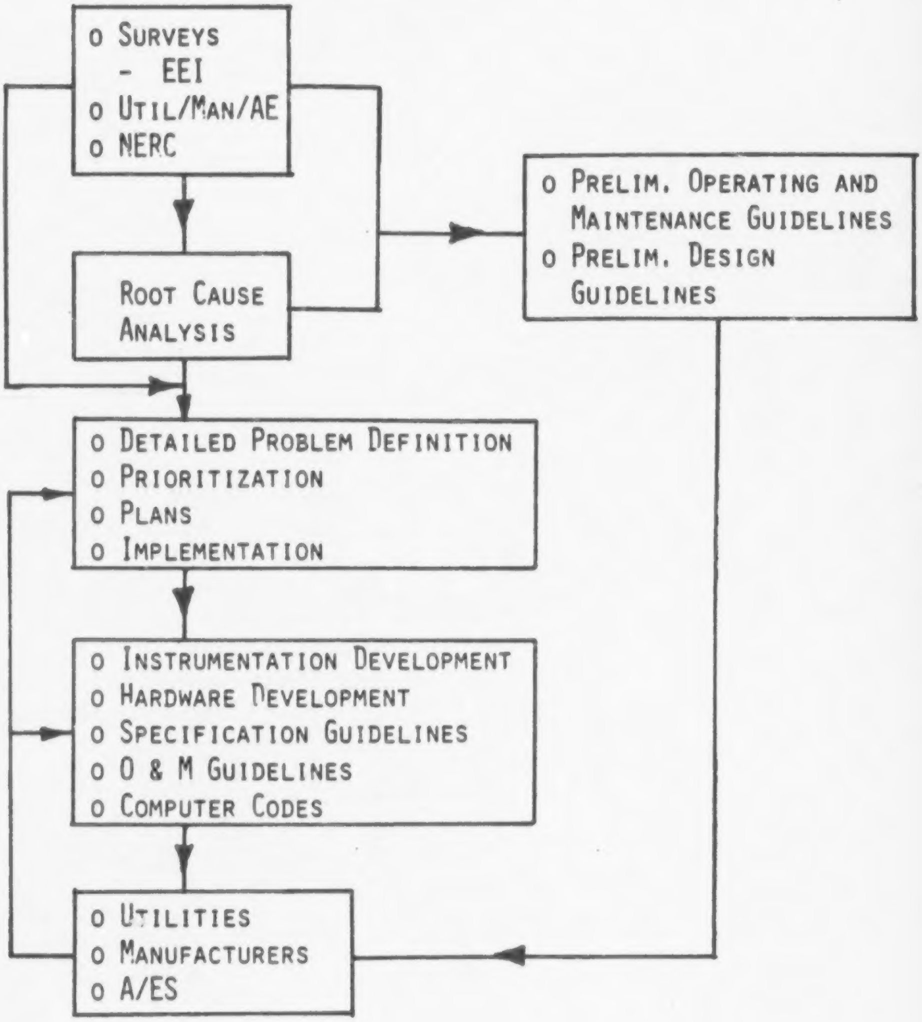
The following are examples of recent results from the EPRI sponsored program for improving the reliability and efficiency of existing power plants. These are indicated together with the initial utility demonstration of the results together with the savings resulting from the initial application on only one power generation unit. As a result of these demonstrations, broad application is proceeding among the industry to satisfy the needs of each company.

Result	USE	INITIAL USER & SAVING
Continuous Assay of Coal	o Coal Blending o Fouling and Slagging Control o Coal Blending	Detroit Edison-$11 million/yr
Coal Cleaning Test Facility	o Improved Reliability o Emission Control	Penn. Electric-$3 million/yr
Plant Performance Modeling	o Improve Plant Efficiency and Reliability	Boston Edison-$1.4 million/yr
Acoustic/Vibration Monitoring	o Avoid Forced Outages	New England Electric-$0.5 million/y
Cycling Guidelines	o Improve Availability and Longevity	Commonwealth Edison-$0.2 million/yr
Dissimilar Weld Quality Control	o Reduce Boiler Tube Weld Failures	Union Electric-$2 million/yr
Condensation-Shock Wave Interaction	o Reduce Steam Turbine Blade Failure	Pacific Power & Light-$2 million/yr
Titanium Turbine Blades	o Reduce Steam Turbine Blade Failure	Commonwealth Edison-$2 million/yr
Chromate Conversion	o Reduce Steam Turbine Blade Failures	Long Island Light.-$1 million/hr
Pulverizer Guidelines	o Improve Coal Pulverizer Reliability and Safety	Utah Power & Light-$1 million/yr
Boiler Feed Pump Guidelines	o Improve Feed Pump Reliability	Tampa Electric-$0.1 million/yr
Scrubber Corrosion Guidelines	o Corrosion Control	S. Mississippi Coop-$8 million
Dry SO_2 Control	o Simultaneous SO_2 & Particulate Collection	P.S. of Colorado-$100/kW
Flue Gas Conditioning Guidelines	o Reduce Derate Caused by Precipitators	Gulf Power-$0.5 million/yr Tampa Electric-$0.5 million/hr
Cooling Water Treatment	o Water and Land Conservation	Colo.-Ute-$9.4 million
Waste Disposal Manuals	o Reduce Byproduct Disposal Cost	Carolina P&L-$2 million/yr

Program	*Subprogram*	*Objectives*
Fossil Plant Performance and Reliability	Steam Generators	Reduce outages caused by metallurgical and other boiler tube failures and ash slagging and fouling.
		Improve cyclic operation and control of boilers and thermal performance.
		Improve human factors interfaces to minimize operator error.
	Steam Turbines	Reduce outages caused by turbine component failures including metallurgy.
		Demonstrate improved cyclic operation, controls, and thermal performance.
		Develop comprehensive guidelines for inspection and maintenance.
	Plant Auxiliaries	Improve air/gas systems reliability and performance.
		Improve reliability and performance of water system components.
		Improve reliability of fuel/ash handling systems.
	Plant Chemistry	Provide guidelines for steam and water purity and ion exchange programs.
		Conduct and monitor field tests on plant components and systems.
	Integrated Plant	Develop design, operation, and maintenance guidelines for improved reliability.
		Improve reliability data systems and determine failure causes.
		Develop optimum plant designs for performance, reliability, and economy.
	Plant Diagnostics	Validate and apply conventional monitoring techniques, improve plant maintenance and reduce forced outages.
		Develop special incipient failure devices to improve plant availability.
		Determine applicability and develop off-line nondestructive evaluation techniques for fossil plant equipment.

Fossil Plant Performance and Reliability Program Logic

FIGURE 1



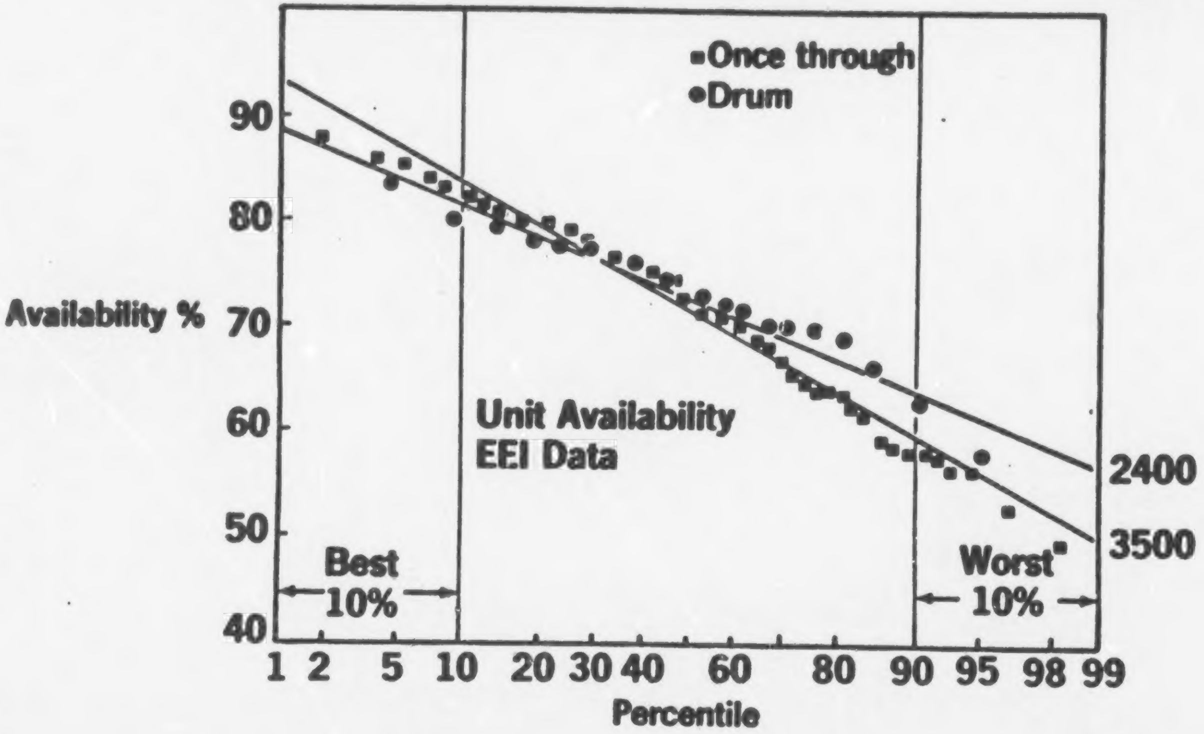
PROGRAM LOGIC

o SURVEYS
- EEI
o UTIL/MAN/AE
o NERC
ROOT CAUSE ANALYSIS
o PRELIM. OPERATING AND MAINTENANCE GUIDELINES
o PRELIM. DESIGN GUIDELINES
o DETAILED PROBLEM DEFINITION
o PRIORITIZATION
o PLANS
o IMPLEMENTATION
o INSTRUMENTATION DEVELOPMENT
o HARDWARE DEVELOPMENT
o SPECIFICATION GUIDELINES
o O & M GUIDELINES
o COMPUTER CODES
o UTILITIES
o MANUFACTURERS
o A/ES

FIGURE 2 - RESEARCH PROGRAM LOGIC

Figure 5.

Unit Availability 2400 vs 3500 psi



Mrs. BOUQUARD. Thank you. Very fine testimony.

Mr. SCHULTHEIS. Good morning. I am Walter Schultheis, vice president of Power Supply Planning and Research for Northeast Utilities. I am pleased to testify here this morning on behalf of the Northeast Utilities companies. Our companies serve Connecticut and parts of western Massachusetts.

I have prepared a very brief summary of the written testimony that has been filed with the committee.

Northeast Utilities feels that excessive dependence on foreign oil as a fuel for electric power generation in New York and New England is the principal existing and future threat to reliability of electric supply for that region.

Since preparing this testimony last week, recent events in the Middle East I think demonstrate again the instability of that region, and underscore our concern with oil dependence.

Presently, New York and New England are dependent for about 45 percent of their generation on foreign oil. The plans of the industry in this region to reduce its present 45 percent dependence include the completion of new nuclear and coal units now under construction. These include three 1,150-megawatt units in New England and two units in New York State, together with two coal units in New York State.

Equally important is our plan for the conversion of approximately 6,400 megawatts of existing units which are now burning oil to convert them back to coal.

A third element in our program is a conservation program to reduce or to hold load growth to reasonable minimum levels. We look for the development of economically feasible hydro potential, although this is quite limited in New England and New York, and for the expansion of economically viable cogeneration facilities.

We further look for the expansion of major transmission interconnections with the Province of Quebec to take advantage of the hydro surpluses expected to exist there until at least the mid-1990's.

The second major thrust of the testimony is that the weakened financial health of the electric utility industry leaves open to question the industry's financial ability to carry those plans I have just outlined to successful completion. Equally important, these financial conditions make timely new commitment to major baseload generation in the mid-1990's unlikely.

Other potential barriers to completing the plan for a reduction of oil dependency in the 1990's include environmental uncertainties and the pitfalls in the regulatory process. Even if our present plans are carried out, New York and New England will still remain about 20 percent dependent on foreign oil in 1990.

In the absence of commitments for new non-oil-fired base-load generating units for service in the 1990's, oil dependence will again begin to increase as greater reliance is placed on additional oil-fired generation and capacity shortages could exist in New England by the mid-1990's.

Northeast Utilities believes that one area of research and development that can be useful to us in meeting the problems of the 1990's is that the fuel cell, because of its unique attributes, could play an important role providing both capacity for reliability and to reduce oil dependence.

The fuel cell's small size, short leadtime and factory fabrication could help relieve the financial problems of the industry in installing new, effective generation. The fuel cell's high efficiency and its fuel flexibility and cogeneration potential make it an attractive oil dependence reduction alternative.

In other words, to assure the availability of a fuel cell in the 1990's, the present program for the phosphoric acid fuel cell must continue on schedule. An essential next step in that program is the completion of testing of the 4.5 megawatt fuel cell currently installed on the Consolidated Edison system in New York and we are hopeful that this program will continue to be jointly sponsored by the Department of Energy, together with electric utility industry sources.

In another area my testimony briefly mentions some of the current industry efforts to maintain and improve transmission system reliability.

That is what the written testimony contains. On reflection, I decided that a few additional comments should be added or emphasized.

While these hearings are focused on reliability, I think we should not overlook the fact that oil dependence has serious economic consequences for our region as well. Coal conservation can save hundreds of millions of dollars and improve the U.S. balance of trade situation. Even brand new capacity which we all know comes only at very high cost these days, is expected to break even with the cost of oil displaced alone in the first 5 to 10 years of its life.

While the purpose of the part of this testimony, dealing with the fuel cell was to describe the unique roll that we see that that device may play in the 1990's, ultimately major base load technology will have to be deployed, and a financially strong utility industry will be needed to carry out that deployment.

The same financial problems that restrict commitment to new baseload units also hinder our ability to support major or new demonstration projects and I am sure that Mr. Yeager would confirm that the support of major demonstration problems, projects, is a major concern of EPRI because its own budget would be I guess pretty well eliminated if we took on several major projects all in 1 year.

Thank you again for this opportunity to appear before you. I will be glad to answer any questions you may have.

[The prepared statement of Mr. Schultheis follows:]

U. S. ELECTRIC POWER SUPPLY RELIABILITY

JOINT HEARINGS BEFORE:

THE SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS

AND

THE SUBCOMMITTEE ON ENERGY RESEARCH AND PRODUCTION

OF

THE HOUSE COMMITTEE ON SCIENCE AND TECHNOLOGY

TESTIMONY
OF
WALTER T. SCHULTHEIS
VICE PRESIDENT
POWER SUPPLY PLANNING & RESEARCH
NORTHEAST UTILITIES SERVICE COMPANY

June 8, 1982

Some Reliability Issues in Bulk Power Supply

While electric utility systems throughout the country have the common objective of supplying reliable electric service at as low a cost as is practical, the existing and future technical, institutional, financial, and facility needs of electric systems vary both by region and by individual utility system. As a representative of the Connecticut based Northeast Utilities system, my perspective is strongly influenced by the situation in the northeast and more specifically is focused on New England. Accordingly, my remarks should be understood to come from that perspective and may not necessarily represent the needs or views of utilities in other areas.

Northeast Utilities views the present oil-dependence of the electric utility industry in the northeastern United States as the single most important threat to economic and reliable electric supply. Since the 1973-74 mid-east oil embargo, my company and many other electric utilities have taken significant steps to reduce their dependence on oil. In 1981, New England supplied approximately 49% and New York approximately 31% of its electric energy from oil-fired sources. While plans do exist for reducing New England's and New York's oil dependence, one must be seriously concerned about the ability of the electric industry to actually implement such plans.

Before discussing the facts of the present and the plans and concerns for the future, let me briefly describe the actions which my company and others have taken in the period since the 1973 oil embargo. In 1973 the Northeast Utilities companies were dependent on oil for 74% of their energy. Although we had been largely a coal-fueled system in the 1960's and earlier, environmental regulations enacted in 1970 caused conversion of all of our plants to low sulphur oil by the early 1970's. This same pattern was generally true throughout New England and New York. By 1981, Northeast Utilities had succeeded in reducing its oil-dependence to 42%. This was achieved primarily by completing Millstone No. 2, an 870 MW nuclear unit, and by the fact that, in response to significantly higher electricity costs caused by the dramatic jumps in oil-prices in 1973 and 1977, our customers have instituted their own methods of conservation and have held load growth to very low levels as compared to earlier times. We also put into place programs to encourage customer conservation.

In the summer of 1974, we commenced construction of an 1150 MW nuclear unit, Millstone No. 3. Originally scheduled to be in service in 1979, that unit has been twice delayed for financial reasons and is now scheduled for service in the spring of 1986. Had we been able to complete Millstone No. 3 on schedule, both Northeast Utilities and New England would now be less dependent on oil and at the same time be benefitting from substantial long term economic advantages that would be reflected in lower rates.

While, as indicated, some reductions in oil dependence have occurred since the oil embargo of 1973/74, other changes have taken place in the electric utility industry which seriously affect our ability to deal with the oil-dependence question or indeed with other areas important to system reliability. The most critical of these changes is the financial deterioration of the industry. Northeast Utilities' experience is typical of that of many other electric utilities over the last eight years.

Our financial strength has been sapped by the effects of inflation, inadequate rate relief, and the high cost of money. The evidence of our financial weakness is that bond ratings have been downgraded from A ratings to BBB and that the market value of our common stock has fallen significantly below book value. In order to minimize the dilution of the interest of existing shareholders, we have limited common stock issues to the bare minimum necessary to maintain an acceptable capitalization ratio. To prevent further deterioration of our financial condition we have trimmed our construction program to the bone. Major generation projects such as Millstone No. 3 have been delayed while other units in the planning schedule have been cancelled.

While we have recently noted some improvement in the regulatory environment in Connecticut, and there is a possibility that abating inflation may relieve some of the upward pressure on costs, basically our financial situation and that of many other utilities remains such as to cast doubt on our ability to substantially reduce oil-dependence in the 1980's and beyond. It is from this perspective that we should consider where we are today and what needs to be done in this decade if we are to substantially reduce our dependence on foreign oil.

New England and New York are part of the Northeast Power Coordinating Council (NPCC), together with our Canadian neighbors in Ontario, Quebec, and New Brunswick. NPCC prepares an annual 10-year forecast of fuel requirements by its sub-areas. Its most recent report,(1) dated December 1981, covers the period 1980 through 1990. Although a new report is in preparation and should be out by the end of the summer, I do not anticipate that its figures will differ markedly from the December document. Figures 1 and 2 (attached) show the actual oil dependence of New York and New England for 1980 and that forecast for the years 1985 and 1990. The forecast shows a decrease in oil dependence both in percentage terms and in absolute usage.

Figure 3 shows the energy share by each fuel type for the the United States as a whole and for the United States portion of NPCC (i.e., New York plus New England) for 1980, and forecast for 1990. While the United States was dependent on oil for only about 12% of its electric generation in 1980, New York and New England were 45% dependent. Thus the oil dependence problem is far more serious for the northeast than for the nation as a whole. Even if the oil reduction programs contemplated in the forecast can be accomplished before 1990--an optimistic assumption from the vantage point of 1982--New York and New England would still remain some 20% dependent on oil for electric generation in 1990. Without further commitments for the 1990's, the percentage will increase thereafter with load growth. As of now, no significant commitments for the installation of new non-oil fired generation in the 1990's have been made for the New York-New England areas.

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(1) NPCC Forecast of Fuel Requirements 1981 - data as of April 1981-prepared by the Task Force on Fuel Requirements.

In summary -

- New York and New England remain heavily dependent on foreign oil for generation today.
- If present plans can be carried out, while such dependence will be reduced to less than half its present levels by 1990, it will still remain at a high level relative to the rest of the nation.
- Present oil dependence reductions plans are threatened by financial strictures and the uncertainty of environmental legislation and regulation.
- We need to be concerned about the period after 1990 as well.

In order to achieve the anticipated oil-dependence reduction by 1990 shown in Figures 1-3, the electric utility systems of New York and New England must successfully achieve the following:

- Completion of new nuclear and coal units now under construction.
- Conversion to coal of units now burning oil.
- Conservation programs to reduce load growth.

- Development of economically feasible hydro potential and cogeneration.

- Expansion of major transmission interconnections with the Province of Quebec to take advantage of hydro surpluses expected to exist until at least the mid 1990's, and with Ontario to take advantage of surplus coal or nuclear capacity.

What are the potential barriers to implementing these plans? We see impediments arising from the following causes: financial constraints, environmental uncertainties, and the regulatory process.

We believe that, given some reasonable improvement in the regulatory climate which controls utility company's retail rates, the nuclear and coal units now under construction will be completed. Such completion will not be accomplished without considerable struggle for companies, such as Northeast Utilities, which are in the process of building the base load units which constitute the major element of the oil-reduction objective. The requirements to raise the capital needed to complete these units will strain their ability to maintain access to the capital markets. This fact will make it difficult for a number of utilities to fund other elements of the program, such as coal conversion.

Coal conversion is the second most important element in the program. Some 2,700 MW of existing capacity are being considered for conversion to coal in New England and 3,700 MW in New York. Several units, including Northeast Utilities' Mt. Tom unit in Massachusetts, have recently been converted. This was achieved with the cooperation of the state government and the granting of Delayed Compliance Orders by the Environmental Protection Agency. Northeast Utilities is contemplating the conversion of four units in Connecticut and three additional units in Massachusetts aggregating some 767 MW. These units can be operated on coal without the installation of flue gas desulphurization (FGD) systems. By the use of 1.0% sulphur coal and with new precipitators installed, primary federal air quality standards can be maintained. At this writing, we have no certainty that we can reach agreement with state regulatory bodies as to an acceptable coal conversion configuration. If FGD systems should be required, as could be the case if certain amendments to the Clean Air Act are enacted, then clearly there would be added cost, delay, and in come cases abandonment of the conversion of some of the scheduled units. The disposal of FGD sludge obviously raises its own special set of environmental concerns. It is unrealistic to believe that commitments for hundreds of millions of dollars worth of coal conversion and FGD equipment can be made without specific disposal sites having been approved and licensed for use by the constructing utility. For all these reasons, while coal conversion is a critical element in our oil reduction program, its accomplishment is by no means a certainty.

Conservation programs at various levels of intensity are now in place throughout the New England region. Conservation decisions are of course in the hands of millions of different home owners and businesses. While impressive reductions in electric use have already resulted from the actions of our customers, the level of future activity is not susceptible to direct control. Conservation must remain as an important element in our overall planning, and it should be regarded as one element in a multi-pronged attack on the problem.

In summary, New York and New England have plans for the 80's which will cut substantially into their oil dependence for the generation of electricity. However there is no certainty that such plans can or will be implemented. We need a greatly heightened sense of importance of the oil dependence issue by our regulators, political bodies, and the population as a whole. This is difficult to achieve right now with so much publicity being given to the "oil glut" of the moment and with the lack of congressional resolution concerning amendment of the Clean Air Act. We need your help and support in gaining recognition of the long-term issues so that the requisite support for completion of projects already underway as well as the initiation of new steps will be forthcoming in a timely manner.

The discussion to this point has dealt with the immediate past, the present, and our plans over the next six or seven years. With the long lead times required for the installation of new generation and transmission facilities, we also need to be concerned with what lies beyond the next six or seven years. It was earlier indicated that few if any commitments have been made for further oil-dependence reductions or for that matter for capacity needed for reliability purposes in the 1990's. With respect to New England, new capacity will not be needed until the mid-1990's for reliability purposes (assuming the effectiveness of conservation measures in keeping load growth at its present low levels). In the absence of commitments for new non-oil fired energy sources, oil dependence will start to increase in the 1990's. Because of the long lead times for the construction of large new base load generation if such units are to be in service by the mid 1990's, commitments would have to be made soon. In our view, it is difficult for us to perceive the circumstances which will lead to any major commitments to new large base load units in the immediate future. The current financial ability of companies already involved in nuclear and coal construction to take on added long-term financial commitments associated with major generation construction ranges from limited to non-existent. We simply do not see a turn around in this situation until after the major construction projects now underway are completed. The result of this, as we see it, may be that we will have to continue to rely on existing (and in some cases aging) oil-fired generation, provide greater encouragement of co-generation (not a necessarily undesirable result if a net oil reduction occurs and over-reliance does not degrade reliability), and place greater reliance on Canadian sources. While the latter two actions offer reasonably practical partial solutions, the continued reliance on aging oil-fired generation is undesirable both from a reliability and oil-dependence standpoint, and of course is not a long term solution in any event.

Northeast Utilities, speaking for itself and, we believe, for other utilities as well, would like to take this opportunity to suggest another practical alternative to the need to reduce oil-dependence and provide needed capacity in the 1990's for reliability purposes. Such an alternative also speaks directly to this Committee's interest in furthering R & D as a means of providing energy resources for the 1990's and beyond.

We believe that the completion of the development of the fuel cell and its commercialization would be an important contribution to solving the particular problems of the northeast for the 1990's which I have previously delineated. The attributes of the fuel cell are particulary suited to meet a number of the needs of the 1990's. Attached, as Appendix 1 hereto, is a description and discussion of the fuel cell, its characteristics, and advantages. This was prepared by one of my associates for another purpose, but I believe it may prove useful background for the Committee and its staff. The attributes of the fuel cell which we find particulary advantageous for its deployment in the 1990's include:

- modular sizing
- short lead time
- factory fabrication
- high efficiency
- fuel flexibility - including ability to use synthetic fuels.
- co-generation potential
- minimal environmental impacts

The first three of these attributes are of particular importance in minimizing some of the financial problems of the industry. From a reliability standpoint financial viability may in fact be the key element. Financially weak companies will tend to undercommit in terms of new facilities, are less technically innovative, reduce committments to R & D, and direct management and technical skills to short term problems. While the commercialization of the fuel cell will not of itself solve all the financial problems of the industry it does offer an attractive generating alternative from a business risk standpoint for the following reasons:

Modular sizing - permits closer matching of capacity and need results in "fewer eggs in one basket"; smoothes out capital financing needs.

Shorter lead time - again permits closer matching of capacity and need thus reducing business risk of over or under supply of capacity; does not tie up large amounts of capital funds in construction work in progress. The latter is a fundamental current financial problem of the industry.

Factory fabrication - in addition to anticipated better quality control during construction, standardized modular units would have a wider market and hence could be reassigned to regions experiencing greater need than anticipated; also manufacturer or third party financing during fabrication are distinct possibilities.

From a reliability standpoint each of the above attributes also offer very positive help in assuring better reliability.

Looking at the fuel cell from the oil dependence reduction point of view its characteristics are well suited; namely:

High efficiency - fuel cells will be much more efficient than many older steam units and gas turbines which they would replace. Initial commercial units are expected to operate at about 8300 Btu, or more than 20% more efficient than much existing steam or gas turbine generation. Second generation fuel cells such as the molton carbonate cell offer the promise of further improvements in efficiency.

Fuel flexibility - fuel cells will have the ability to operate on natural gas, light petroleum distillates, methonal, medium Btu gas from coal gasification, and other synthetic fuels. Thus while the availability of synthetic fuels and gas from coal gasification is uncertain in the early 1990's, fuel cells will have the capacity to change over to newer fuels as required.

Co-generation potential - the relatively small size and modular nature, good environmental and siting characteristics, and the availability of usable reject heat offers good co-generation potential and accordingly an opportunity to increase overall fuel efficiency.

The environmental characteristics should permit reduced regulatory delay and flexible siting. Thus, the fuel cell offers an alternative form of generation which would overcome a whole series of problems we foresee in assuring that suitable generating capacity will be available in the 1990's both for reliabiltiy and oil reduction purposes. Its timely availability could allow fuel cells to play an important role in the 1990's.

It is believed that all of the major technical research obstacles to the development of the fuel cell have been resolved. Two 4.8 MW demonstration units, one in Japan and one in New York City, are in place and undergoing preliminary testing. The New York City unit is being financed jointly by DOE, EPRI, ESEERCO, Consolidated Edison Co., Niagara Mohawk, and Northeast Utilities. The completion of operational testing of these units is an absolutely essential step in commercialization. We urge continued adequate funding of this effort in the DOE's Fiscal Year 1983 budget and recognize and appreciate that both Chairman Fuqua and Representative Hamilton Fish have supported this need in statements before the House Interior Appropriation Subcommittee. While continued support of research on advanced fuel cell concepts, such as the molton carbonate cell, are important, it is our opinion that unless the phosphoric cell is commercialized in the decade the entire fuel cell program will suffer a grave setback and its availability will be indefinitely deferred. It is anticpated that a plan of commercialization will be developed by the Fuel Cell Users Group within the next year. In all likelihood this will entail commitment by individual utilities to purchase, install, and test a number of full scale commercially designed units. The number of units must be large enough and priced high enough to justify the creation of a production-type facility. The successful completion of a fairly large scale deployment of prototypes is then expected to lead to the availability of fuel cell units on a commercial basis in the 1990's. The commercial availability of this new electric generating facility will give us a useful resource in meeting both the reliability and oil-reduction needs of the 1990's.

Turning to another subject, transmission system reliability is a key element in the reliable supply of electric service. I believe the record would show that many major widespread blackouts have been traced to transmission system design and operational problems. Today, transmission systems are being heavily loaded in order to permit the transfer of energy from one region to another. Such heavy transfers are motivated by economics, primarily the substantial fuel cost savings which are available if the presently available surplus coal-fired energy in some regions can be used to displace oil-fired generation in oil-dependent regions. These heavy transfers increase the risk of voltage collapse or system instability in the event of the loss of more than one critical facility. The industry is reacting to the perception of increased risk by more intensive utilization by the pool dispatch centers of existing analytical tools, by the installation of better system control and data acquisition systems (SCADA) and by greater emphasis on the training of its operating personnel. Through the Electric Power Research Institute (EPRI) the industry is developing new and more sophisticated computer simulation models for use both in planning and operational studies. Many of these programs may be characterized as composite reliability programs since they reflect and assess the impacts of both the loss of generation and the loss of transmission facilities on thermal overload and voltage conditions. Additionally, the industry has developed and is continuing work on long-term dynamic stability programs.

Another example of R & D being done in the reliability area is a program for composite bulk power electric system adequacy assessment which is under development by NPCC, with further work being done by

EPRI. The program is to be used to assess the composite effect of generation and transmission unavailability on the overall adequacy of a complex electric power supply system. Indices are developed to measure the risk of occurrence of overload conditions in circuits and transformers to provide means to identify potential weak bulk power supply segments. The salient feature of the program is its ability to automatically select and subsequently test contingencies deemed likely to produce system failure conditions. The utilization of such a technique lends itself to the needs of a large and complex power supply system such as the one which exists within the boundaries of NPCC. A great deal more effort and understanding is required before this technique will become a practical tool for the industry.

With respect to operator training, in June, 1981 the Department of Energy issued a report on "Electric Utilities' System Operator Selection and Training" (DOE EP-0017). We believe this is a worthwhile, comprehensive guideline for the training of bulk electric power supply system operators. It is our understanding that the reliability councils are addressing the questions raised in this document. Accordingly, this important area is under review by the industry and is being followed by the DOE.

Each year the North American Electric Reliability Council (NERC) publishes its Annual Review of the Overall Reliability and Adequacy of the North American Bulk Power Supply Systems. These reviews provide a means for alerting all parties of trends within the industry which can have an adverse impact on system reliability. NERC also publishes an

Operations Review of Overall Reliability and Adequacy of the Bulk Power Supply for each summer and winter of the coming year.

The regional reliability councils also conduct joint studies of system performance as required. For example, the combined effect of the interconnection between Ontario-Hydro and General Public Utilities, the proposed Hydro-Quebec-New England Interconnection and the increased New York-Hydro-Quebec Interconnection are being studied jointly by MAAC, ECAR, and NPCC reliability councils (the so-called MEN Studies) to determine the reliability impact that such new interconnections will have on the bulk power supply systems of the northeast.

While there will always be opportunities for improvement in hardware and analytical techniques for transmission system planning and operation, we have not identified any special area of R & D which is critical to transmission reliability. The public's dislike of transmission lines in general and the uncertainties associated with the siting process provide continuing uncertainty as to the industry's ability to complete necessary facilities in a timely manner. R & D, in terms of providing transmission line designs which can better utilize existing rights of way and thus increase the acceptability of new facilities, is being carried out by EPRI.

The Committee's charter for these hearings makes it clear that it recognizes many of the problems of the electric utility industry. Fundamentally, we need a consistent long range national energy policy which includes appropriate recognition of the importance of a strong electric utility industry. Such a policy must be well articulated and must be "sold" to the states. To be realistic, it must recognize the inevitability of trade-offs between short and long-term economics, the environment, and reliability of supply. Northeast Utilities is prepared to participate with you in whatever practical ways it can to achieve such an objective.

Prepared by:
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June 4, 1982

PERCENT ENERGY GENERATED AND PURCHASED BY FUEL TYPE

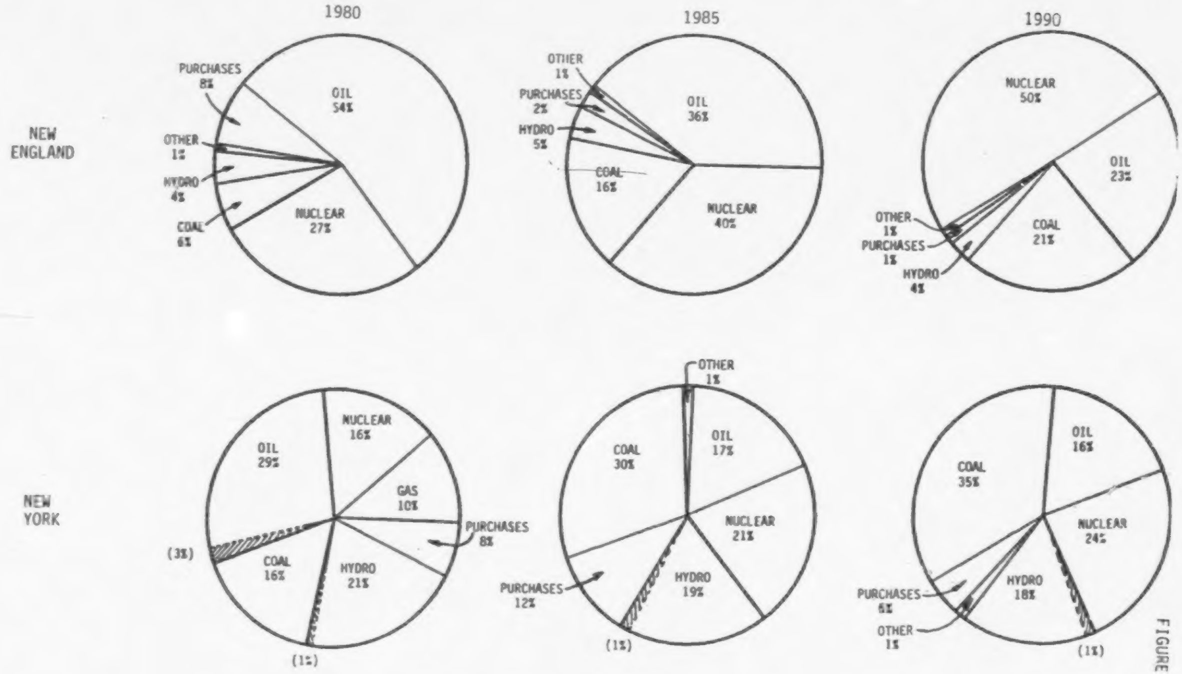


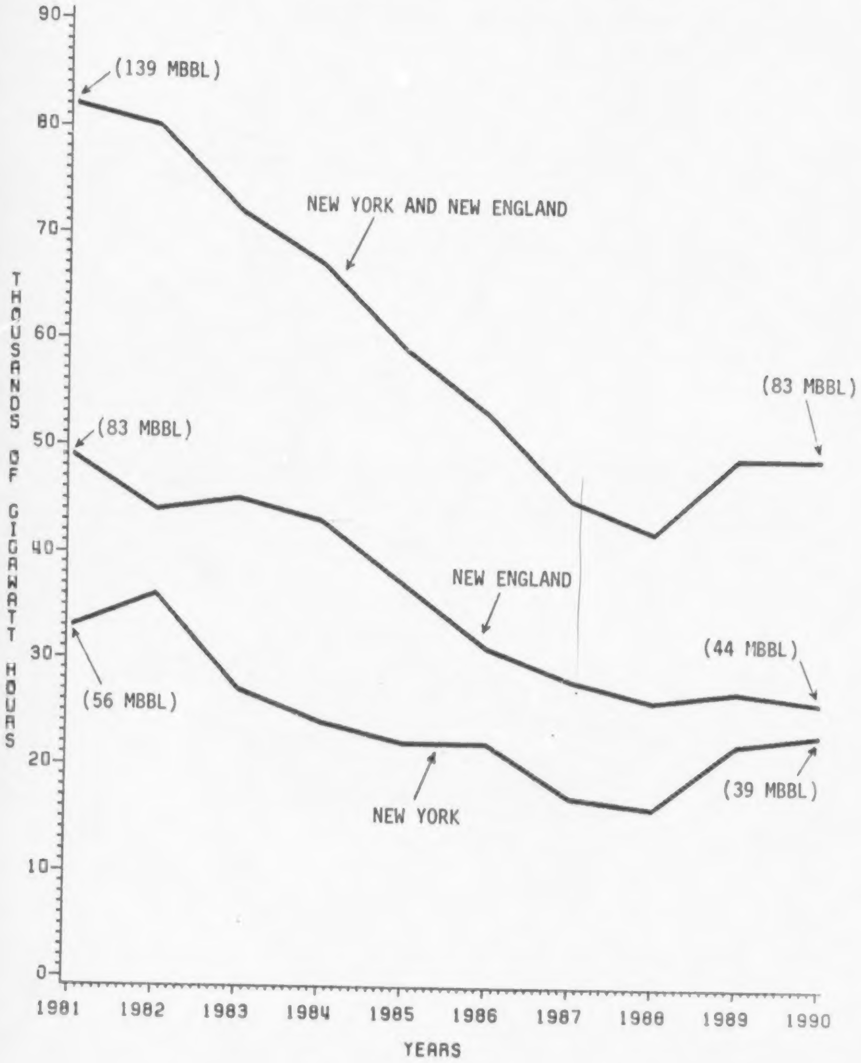
FIGURE 1

(%) Figures in brackets show that portion of total generation being sold (shaded region)
This amount is already included in the resource total.

SOURCE: NPCC Forecast of Fuel Requirements - Dec. 1981

FIGURE 2

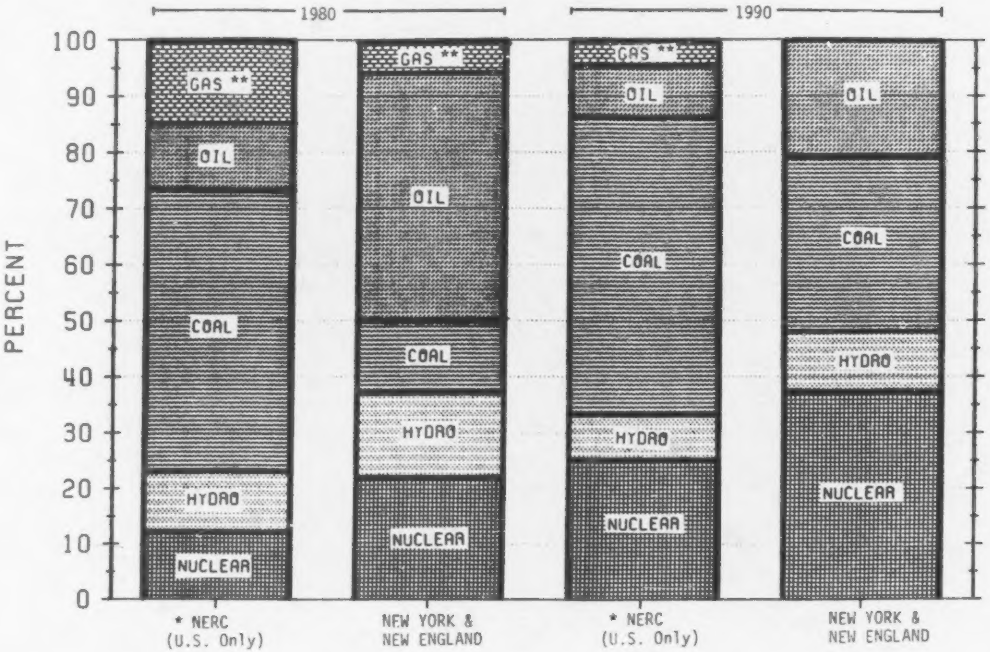
PROJECTED ENERGY FROM OIL



SOURCE: NPCC FORECAST OF FUEL REQUIREMENTS – DEC. 1981

FIGURE 3

PERCENT ENERGY BY FUEL TYPE
(PLANNED GENERATION SCHEDULE)



* 1980 Summary of Presented Peak Load Generating Capability & Fossil Fuel for Requirement
** Includes Energy from "Other"

SOURCE: NPCC Forecast of Fuel Requirements - Dec.. 1981

APPENDIX 1

UTILITY PLANNING PERSPECTIVES FOR THE FUEL CELL

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INTRODUCTION

For the past several years, the fuel cell has been in various technical development phases. The technology itself was demonstrated for utility use by successful operation of a 1 MW pilot plant by United Technologies Corporation (UTC) in 1977. The 4.5 MW demonstration plants in New York City and Tokyo, Japan are expected to show the utility industry that this new resource has come of age. These demonstration plants will show the unique characteristic that fuel cells possess for utility application, and that they should now be seriously considered as a viable energy resource by utility planners for inclusion in their generation mix plans.

A consortium of 37 utilities formed a Fuel Cell Users Group (FCUG), in 1980, whose objectives were to promote the attributes of the fuel cell. The FCUG has several subcommittees including a System Planning Subcommittee. The System Planning Subcommittee's purpose is to make utility planners aware of fuel cell developments and its attributes. It also provides technical guidance to fuel cell manufacturers to produce an energy resource with superior characteristics that will have significant appeal to utility planners. Thirteen senior planning engineers have worked in concert with manufacturers for the past year to develop preferred and acceptable fuel cell characteristics, which the utility industry would deem noteworthy. Table 1 outlines these preferred and acceptable fuel cell characteristics.

The resultant proposed design characteristics for a fuel cell are expected to provide a utility with a new resource which has: enhanced planning flexibility; superior operational characteristics; environmental acceptability; and potential for cogeneration applications. The following discussion of each of these fuel cell attributes makes it apparent that the fuel cell can be a valuable asset to utility systems in the future.

ENHANCED PLANNING FLEXIBILITY

The major fuel cell attributes from a planning perspective include its: high efficiency; high availability; factory manufacture allowing quality control; short installation lead times; reduced business risk; ability to improve company finances; small size; dispersed siting capability; and multi-fuel capability.

High Efficiency is one of the most valuable attributes that the fuel cell has to offer the utility industry. Because a fuel cell is an electrochemical process which converts hydrogen-rich fuel directly to electricity it is not limited by thermodynamic or mechanical efficiencies. This makes the fuel cell uniquely

Table 1

Generic Values of Fuel Cell Characteristics

Characteristics	Preferred	Acceptable
Emissions (lb./10^6 Btu) SOx NOx TSP (Particulates) Smoke	Existing regulations	Existing regulations
Heat Rate	8300 Btu/kWh	8300 Btu/kWh
Unit Size	5 MW	10 MW
Single/Multiple Units	Up to 4 per site	Up to 2 per site
Land Requirements	Min. Possible	Approx. 600 ft^2/MW plus fuel, water and gas storage.
Availability	95%	90%
Power Dispatch	Variable	Incremental steps
Real Power Response		
o minimum to maximum	1 sec.	1 min.
o standby to maximum	15 sec.	2 min.
Reactive Power Response	±10 MVAR in 0.2sec	±10 MVAR in 0.5 sec.
Unmanned Operation	Yes	Yes
Black Start	Yes	No (Available as option)
Cooling Mode	Dry	Site specific
Noise	55 dbA @ 100 ft.	Site specific
Aesthetics	Outdoor low profile	Site specific

qualified to contribute to conservation programs through its ability to reduce oil dependence. Fuel cell design heat rate is expected initially to be about 7900 Btu/kWh increasing to 8300 Btu/kWh only after more than 4 years of operation. These heat rates are better than most fossil steam units in the United States of America. Moreover, at part loading, the fuel cell's heat rate will not increase substantially.

Analysis performed to guide the manufacturers as to the appropriate heat rate, provides some insight into the workings of the System Planning Subcommittee of the Fuel Cell Users Group. One year ago, there was concern as to whether the utility industry would prefer a 9300 Btu/kWh unit or an 8300 Btu/kWh unit with a higher capital cost. Figure 1 shows analysis performed by the System Planning Subcommittee to determine the maximum increase in capital cost value that could be cost justified in order to reduce the fuel cell's heat rate by 1000 Btu/kWh.

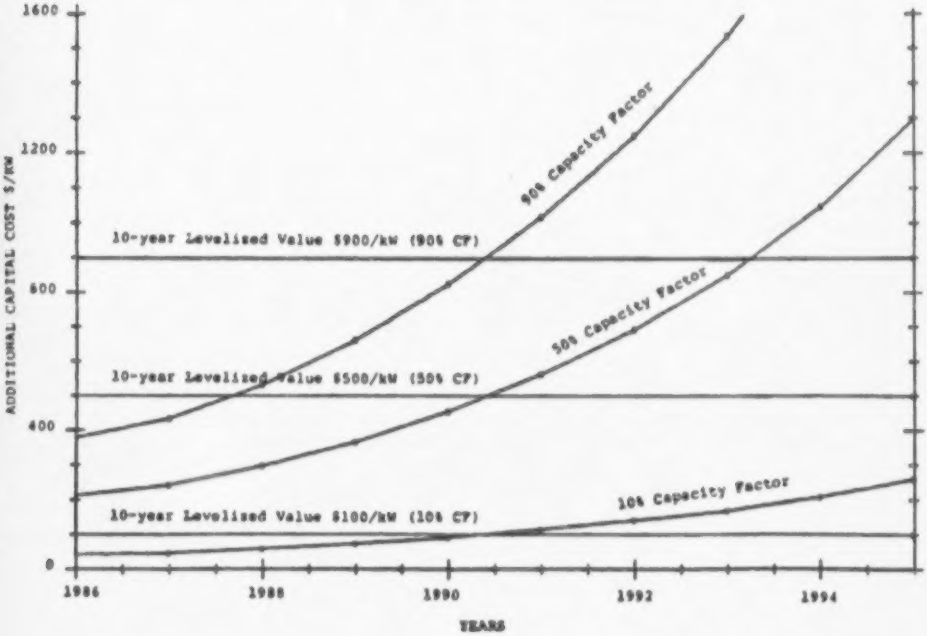


Figure 1

Maximum Additional Capital Cost to Justify a Reduction of 1000 BTU/KWH in Fuel Cell Heat Rate

In this analysis resultant savings in fuel costs have been translated into the maximum increase in capital cost the utility industry would be willing to pay to achieve such savings. The resulting additional capital cost values depend upon the capacity factor assumed for operation of the fuel cell. Thus, Figure 1 shows results for a fuel cell operating either base loaded, (90% capacity factor), intermediate loaded, (50% capacity factor), or in a peaking mode, (10% capacity factor). The results, expressed in 10-year levelized terms, show that a reduction of 1000 Btu/kWh in heat rate would be justified by an additional capital investment of $900/kW at 90% capacity factor, $500/kW at 50% capacity factor, and $100/kW at 10% capacity factor. These values are substantially greater than the investment required by manufacturers to produce such an improvement in efficiency. Thus, the System Planning Subcommittee recommended that the preferred and acceptable heat rate should be the highest efficiency achievable.

High Availability of the Fuel Cell is expected because of the fuel cell's modular construction. Modular construction will facilitate ease of repair when either forced out of service or during scheduled outage maintenance. Moreover, there are no moving parts in the fuel cell which are subject to significant mechanical or thermal stresses, thus minimizing failure of such components. With a projected high availability of 90%, a utility system which installs a substantial amount of fuel cells can reduce its reserve margin requirements while retaining the same system reliability. Thus, not only are cost savings affected by having the units operate longer hours with reduced maintenance costs, but cost savings are also accrued by installing less capacity.

Reduction in Business Risk will be achieved by the fuel cell's shorter lead times, and because the fuel cell will be manufactured in a factory. The ability to install fuel cell capacity in less than three years, from initial planning to installation, will substantially reduce the business risk. Compare the fuel cell's lead time to large base load units which may need 10-14 years before commercial operation. Ideally, future load forecasts for horizon years, when installation of new capacity is being planned, should be sufficiently accurate or the range of possible loads sufficiently small, to ensure that capacity additions are justified under all conditions. Fuel cells would, therefore, reduce this uncertainty significantly by moving the horizon year from 14 to 3 years. Manufacturing fuel cells within a factory will promote quality control and reduce delays caused by outside construction due to exposure to the elements.

The Smaller Size of the Fuel Cell will facilitate a much better capacity fit to expected load growth. The installation of one large unit could produce excess capacity for several years, particularly if the forecasted load growth for a utility system is small. Additions of small discrete increments of capacity would allow better matching of capacity to load requirements.

Improved Company Finances can result from installation of the fuel cell. The ability to order and place in service in a short time, small discrete units of capacity can be financially beneficial and would offer the financial planner greater flexibility. The financial planner can expect annual cash flows associated with the lesser capital intensive fuel cell installation to be relatively constant, whereas the expenditures required for large base load units, once the commitment is made, can increase significantly each year until its commercial operation. In periods of very high interest rates, the financial planner may find it prudent to limit the debt service of the utility company. Delaying the installation of small increments of fuel cell capacity allows some degree of flexibility, without substantial cost penalty. One or two fuel cell units could be delayed without creating significant reliability problems. However, even a modest change in a large base load unit's schedule could cause substantial reliability difficulties and cost increases.

Dispersed Siting Capability of the fuel cell can have substantial appeal to certain utility systems. Dispersed siting can defer transmission and distribution investments, reduce transmission and distribution losses, and provide for active and reactive power control directly at the load centers.

The Fuel Cell's Multi-Fuel Ability to use natural gas, methanol, light petroleum distillates, and eventually, medium BTU gas from coal gasification or other forms of synthetic fuel, demonstrates the versatility of the fuel cell to react to future changes in fuel sources. Accordingly, this technology will not become redundant overnight because of the unavailability of certain fuels. Moreover, it does not require large additional capital investments to switch from one fuel to another.

SUPERIOR OPERATIONAL CHARACTERISTICS

The fuel cell has a number of operational characteristics which are expected to be superior to conventional technology. The fuel cell can precisely follow real power load changes, has very fast reactive power response and does not contribute to short circuit fault levels. These three features allow the fuel cell to provide corrective responses to transient or system disturbances. Other operational features are its ease of maintenance, low operational cost because of unmanned operation and contribution to rapid system restoration because of its blackstart capability.

Real power response time of the fuel cell is very fast. The fuel cell is expected to change from minimum load levels to maximum load levels in about one second. While such a short response time is not always necessary on a utility system, this ability provides an opportunity for improved economic dispatch. The relatively flat heat rate curve is well suited for load following applications without cost penalties. The real power response time can also allow a utility to have reduced spinning reserve on its system, because the operator can rely upon its quick response time to provide almost instantaneously spinning reserve if required.

Fast reactive power response capability of a fuel cell enables it to react to voltage surges and swings, and will dampen voltage oscillations which are likely to be experienced during lightening storms and switching operations. The fuel cell will generate or absorb system reactive power over a significant range controlling voltage level to a high degree of accuracy. The fuel cell, therefore, can provide an alternative to an equivalent amount of shunt reactors or capacitors.

Moreover, the fuel cell can act in this reactive mode even though the fuel cell is not operating. A utility system with a significant number of fuel cells is more likely to survive transmission cascading and voltage disturbances which have caused widespread blackouts in the past.

The short circuit fault characteristic of the fuel cell is such that if a fault appears on the system, the short circuit current input from the fuel cell would be limited. This feature reduces the necessity for higher rated breakers to interrupt the short circuit fault current.

Unmanned and Blackstart Capability of the fuel cell allows it to be located in remote areas, yet contribute significantly to local area disturbances without substantial cost. Many major system blackouts are caused by cascading transmission failures that result in system backup which form "islands". To maintain continuity of electric services each island must maintain a balance between power generation and load demand. This usually places extremely severe frequency regulation requirements on generating units and they may ultimately trip off line because of over or under frequency relay actions. The fuel cells' extremely short response capabilities and ability for dispersed siting which places it close to the load, can be valuable assets that diminish the probability of system blackouts.

ENVIRONMENTALLY ACCEPTABLE

The fuel cell has significant environmental advantages: very low emissions; efficient utilization of land, low noise levels and no striking visual impact.

Fuel cell emissions, summarized below, are much better than those allowed by Environmental Protection Agency (EPA) rules.

Table 2

Fuel Cell Emissions

Contaminant	FCG-1 Emissions lb/million Btu	EPA Limits* lb/million Btu
SOx	0.00003	0.8
NOx	0.02	0.3
Particulates	0.000003	0.1

*New Source performance standards.

Moreover, if new or expanded fossil burning installations are planned, which are below the Federal or State emission limits, then emissions from other facilities in the area may be increased by a proportional amount (the bubble concept). As a consequence, emission offsets from fuel cell installations could contribute greatly to; the total reduction of emissions; or improving economic dispatch of other neighboring plants by allowing emissions to be traded. Under this latter criterion fuel cells could be added to existing generating stations where their negligible emissions could offset emissions from capacity that did not comply with the standards. Thus, fuel cells could be used to offset or defer the costs of scrubbers or other emission control equipment required on existing units for conversion to coal.

Land use associated with the installation of a fuel cell is much less than for a similar size conventional generation units. The fuel cell's modular construction lends itself to be sized and designed for most site configurations. Virtually no cooling water requirements are required, thus, it could be located at remote sites or use sites which otherwise could not be used by conventional units.

The noise level from a fuel cell is expected to be very low; about 55 decibels at 100 feet. Since there are no moving parts, the only equipment which contributes to noise levels are the pumps and fans of the fuel cell's auxiliary equipment and the transformer required to increase the unit voltage to transmission voltage level. It is expected that soundproofing or baffles would reduce these levels even further if required.

Low profile aesthetics of a fuel cell with no stack, would allow it to be placed, without intrusion, into residential or scenic areas.

COGENERATION POTENTIAL

The fuel cell has unique characteristics which make it attractive for cogeneration. It is small and discrete in size, environmentally acceptable, and has versatile fuel use. Each of these attributes make cogeneration applications viable to certain industrial or commercial processes that would otherwise not consider cogeneration. The fuel cell, therefore, has siting capabilities which permits it to be located in residential or commercial areas, close to potential consumers of reject heat. The reject heat is expected to be in the form of 180° F water, and 350° F saturated steam, at 60 lbs. per square inch. While this is low grade heat, it is of a quality that is valuable to many manufacturing processes and for district heating systems.

BIOGRAPHICAL DATA

WALTER T. SCHULTHEIS

Walter T. Schultheis is vice president - Power Supply Planning and Research for Northeast Utilities (NU), a registered holding company formed in 1966, whose principal subsidiaries are: The Connecticut Light and Power Company, The Hartford Electric Light Company (HELCO), Holyoke Water Power Company, Western Massachusetts Electric Company, Northeast Nuclear Energy Company, and Northeast Utilities Service Company.

Schultheis received a bachelor of science degree in electrical engineering from Rensselaer Polytechnic Institute, Troy, New York, and studied economics at Trinity College Graduate School in Hartford, Connecticut.

He joined Connecticut Power Company, a predecessor of HELCO, in 1950, as an engineering assistant at New London. He held various operating and planning positions until 1966, when he came to NU as a staff engineer. He was named manager - Capacity Development in 1970 and director - Capacity Planning in 1974. He became director - Research and System Planning in 1977. He assumed his present duties in July 1979.

Schultheis is a member of Edison Electric Institute's (EEI) Committee on Interconnection Arrangements, Electric Power Research Institute's (EPRI) Energy Management and Utilization Division Committee, and Northeast Power Coordinating Council's (NPCC) System Design Coordinating Committee, and the Planning Committee of the New England Power Pool. He is also a director of Vermont Electric Generation and Transmission Cooperative, Inc., and director for Gas-Cooled Reactor Associates. He also has been a member of EEI's System Planning Committee and has been very active in various New England Power Pool matters. He has been a company witness at a number of regulatory hearings.

6/1982

Mrs. BOUQUARD. Thank you very much for your testimony.

Mr. FOGARTY. I am Dave Fogarty with Southern California Edison Co.

I would like to paraphrase a few things included in my filed report and speak a little bit more about the reliability of a system as seen by the customer.

Mrs. BOUQUARD. Mr. Fogarty, you may proceed as you wish and your entire testimony as well as the entire testimony of Mr. Schultheis will be made a part of the record.

Mr. FOGARTY. Thank you.

Southern California Edison Co., was incorporated in 1909 and provides electric service in a 50,000-square-mile area of Central and Southern California. This area includes some 800 cities and communities with a population of over 8 million people and 3¼ million customers. Our system is a summer peaking system. Demand last year was equal to 13,738 megawatts. We have a needle peak demand, which is different from those in Arizona, Texas, and Florida, in that 17 percent of our annual demand encompasses less than 1 percent of the energy we transmit for our customers. This presents us with unique problems and unique opportunities.

The system last year utilized eight primary energy resources including oil, gas, coal, nuclear, hydro, wind, solar, geothermal. This makes us unique among utility systems in using so many primary energy resources.

Transmission reliability has been a very important thing on our system for a number of years. Going back to 1918, transmission lines linked our system to the San Francisco Bay area and the drought of 1924 underscored the need for such interconnections when significant amounts of power were exchanged with PG&E on a regular basis.

Also, our hydrosystem which supplied 90 percent of our energy during the decades of the thirties and forties was built during the decade of the twenties in the Fresno area. This is about 200 miles of transmission,.some 50 years ago.

In 1937, the Hoover Dam project was completed and the bulk of that energy flowed into the Los Angeles area, either to the Department of Water and Power, or to my own company.

In the late sixties, an AC intertie was built to connect the Southern California area with the Bonneville system and also a DC line was built in the western part of the United States I think we have been more dependent upon transmission lines for resources than in any other part of the country.

To indicate another measure of this transmission dependence, last year we imported 26 percent of all of the energy we provide to our customers and this year we expect to import some 30 percent. This means that 30 percent of all the kilowatt-hours we provide to our customers will be produced on other systems by systems that were built, operated and maintained by other utilities. We have no involvement with them other than through a contract path.

I would like to move, if I could, and ask you to look at the last page of my filed statement, attachment C, which goes to the reliability of our system as seen by our customer. We have tabulated their material we put out each year in accordance with EEI standards, the total interruptions our customers see that is categorized under the average customer minutes of interruption per customer.

It is a large chunk of information to swallow, but it does give us a comparison between systems and against our own system as to how we are doing compared to how infrequently we interrupt the customer.

In the right hand column, we have system reliabilities that range in the 99.8 to 99.99 percent. That is availability, or times when the customers are receiving service from us. Most of our deviations from the norm—you can see the 20-year average is 42.61 minutes per customer—our system is not as weather sensitive as most systems, but for example, in 1978 you can see we had 87 minutes of interruption; 46 of those minutes were due to storms. In 1969 we had some 69 minutes and again here 39 minutes were storm related. There are some nine catetories of interruptions we have in this statistical presentation, one of which is generation. I might point out that since 1966 we have not had any interruptions on our system that were generation-related.

Last year, for example, again zero generation-related interruptions; 5 percent of the interruptions were transmission related and 95 percent of the interruptions were due to problems on the distribution system.

If I could ask you to move to attachment B, which is the page before that, I can talk a little bit about some of the significant transmission interruptions.

For example, on August 29, 1981, we had a 1,479-megawatt load shed on our system, due to problems in the Pacific Northwest. We had an interruption there that caused the frequency and our system to drop to 58.96 Hertz at about 1:30 in the afternoon. This was an out-of-step operation in northern California, in the tie between northern California and Portland.

This, as you can see, caused an interruption of nearly 1,500 megawatts which was quite substantial, more than 10 percent of our load, but because we anticipated this, because we interrupted load to our customers as the frequency decreased, we were able to restore the system to normal in a time of from 3 to 12 minutes. The first increment of load shed was back in 3 minutes and the last increment in 12 minutes.

As I pointed out earlier because we have grown up with these long transmission lines, we are very dependent on them. We do have very sophisticated load shedding systems to sacrifice the service to a few customers for a short period of time, in other words, to preserve the integrity of the whole system, and I think the record speaks for itself. It has been quite good.

A final item I would like to mention is our dependence on renewable and alternative energy resources. You may be aware that Edison has made a substantial commitment to this program and we are looking to add about 2,000 megawatts from this source to our system during the decade of the eighties.

Some questions come up, though, relative to reliability and availability of these systems. Our first question relates to the capacity value these systems will have at time of system peak. Under the PURPA rules and under the rules our own public utility commission follows, we may pay a capacity charge as well as an energy charge to the entrepreneur who develops the resource. This resource though might not be available at the time of system peaks so we are paying him for capacity that may never be available to us.

For example, from wind. Wind machines are typically only going to be available at about 25 percent of their nameplate rating at time of system peak. That is based on a study. It is not based on any empirical data but that is an anticipation on our part.

A second problem with the renewables and alternatives is that the maintenance requirements will not be governed by the utility. The maintenance requirements will be in the hands of the entrepreneur. It may be to his advantage to maintain the units and keep them operating or it may not. Certainly a 37½ percent investment tax credit for solar might lead you to abandon maintenance after a few years, when he has had his investment pay out.

A third problem is the availability of renewable and alternative resources to follow load changes. Most of these that we have seen we don't think could participate in load following. With a system of perhaps 17,000 megawatts in 1990 and only 2,000 megawatts of renewable and alternatives, this would not be a serious problem but in another 10 years it might be a larger percentage of our system and we would have to develop means to require the renewable and alternative resources to become load following, through cycling the customer's load.

A fourth concern is with the cogeneration projects, themselves, we think they are going to be controlled by the process requirements rather than by the requirements of the electric system and this may pose some problems for us.

Certainly the cogeneration equipment that is being used is for the most part powerplant quality. It is more reliable, it is known, there is not system uncertainties with that as there are with windmills and some of the solar schemes, but it will be dictated by the process requirements rather than by the utility requirements.

One other item and I will close on this one. Because we have the needle peak that I mentioned earlier, we have done a number of things to try to match our system characteristics to that needle peak. Certainly being interconnected so that we can purchase for short periods of time the demand requirement is one of them and we have used that for a number of years.

We also have a number of peaking units on the system. We are moving further into the customer side now to try to interrupt the customer or cause the customer to alter his behavior pattern. Some of the things we are doing in that area are to have an interruptable rate schedule for some of our larger industrial customers. There is some 156 megawatts, or a little over 1 percent of our peak, which is in this category. We charge the customer a lower rate, but we have the ability to interrupt him on 10 or 30 minutes' notice and this helps us to shave the peak and make it better for us to meet the load.

We also have a number of customers, I think about 500 megawatts' worth on a voluntary load reduction program. Upon receipt of a phone call from us, these customers have agreed to curtail their use of electricity.

We made a telephone check last year to see if that 540 megawatts was really still there and we did determine that 438 megawatts were available at the time we called so we think that is a good system and one that we are happy with.

We have residential air-conditioning cycling programs where we cycle an air-conditioning unit on and off at time of peak demand and final item is one that we are particularly excited about, and that is a demand subscription service whereby the customer selects a minimum level of service which will satisfy his needs during electric utility system deficiencies. We put a collar between the meter and the customer's load, it is about 4 inches deep, and plug the meter into this collar. It has a radio receiver that will alter the customer's demand by limiting him to 6 or 8 or 10 amps at time of system need. During the rest of the time he is free to take as much power as he chooses from us. But we again will pay him for this.

We have plans to install 100,000 of these devices during the next 2 years, and again to shape the load by modifying the customer's behavior.

I think that covers the points I wish to make. Thank you very much.

[The prepared statement of Mr. Fogarty follows:]

June 1982

Prepared Comments of

David J. Fogarty
Executive Vice President
of the Southern California Edison Company

Before the
House Committee on Science and Technology
Subcommittees on Energy Development and
Applications and Energy Research and Production

The Southern California Edison Company (Edison) and myself appreciate the opportunity to share with you, the technical lawmakers of our Country, some of the power system reliability milestones Edison has and is in the process of accomplishing. In addition, I will attempt to characterize some of the major reliability concerns and uncertainties which exist at this time.

I joined Edison in 1961 as a Mechanical Engineer in the Engineering and Construction Department and in 1971 was elected Vice President of the System Development Department. Since then I have served as the responsible Officer of the Power Supply and Customer Service Departments, prior to my election in 1977 to Senior Vice President. In January 1982, I become Executive Vice President responsible for the Power Supply, Engineering & Construction, System Development, Advanced Engineering and Nuclear Engineering & Operating Departments.

Incorporated in 1909, Edison provides electric service in a 50,000 square-mile area of Central and Southern California. This area includes some 800 cities and communities with a population of over eight million people and 3½ million customers.

Edison's gross investment in utility plant totals more than $9.5 billion. The area generating capacity during the peak in 1981 was 15,592 megawatts of which 67% was accounted for by oil and gas-fired generating units. Edison's joint participation in coal-fired generating units in Nevada and New Mexico account for another 10% with 6% generated from Company hydroelectric plants. The Company's joint participation in a nuclear plant provides 2% with the remaining 15% acquired under contracts with other utilities. Edison utilized eight primary energy resources in 1981 including oil, gas, coal, nuclear, hydro, wind, geothermal and solar.

In order to take advantage of the economics and increased reliability associated with pooled resources, Edison has a long history of interconnected operation. As early as 1918, transmission lines linked Edison to its neighbors as far north as the San Francisco Bay area. The drought of 1924 underscored the need for such interconnections when significant amounts of power were exchanged on a regular basis.

Edison is a summer peaking utility (1981 area peak demand of 13,738 megawatts) whose annual system load duration curve exhibits the shape of a "needle peak" as shown by Attachment A. As can be derived, the upper 17% of the annual demand encompasses less than 1% of the annual energy requirement. In order to be cost effective while serving this low energy production demand, Edison has incorporated various generation, load management and power contract arrangements. Among these are exchange agreements with utilities in the winter peaking Pacific Northwest. These mutual support arrangements utilize two 500 kV AC lines and one 800 kV DC line connecting Oregon to Southern California and characterize one of the fundamental reasons the Congress of the United States approved the Pacific Intertie agreements which allowed for the construction of these facilities in the late 1960's. Unlike typical interstate transmission which is constructed to transmit power from new generating facilities, these lines were justified on the anticipated benefits derived from improved reliability and economical power exchanges and sales. Today, it is very difficult to receive the joint approval from the various state regulatory agencies in siting and constructing regional transmission lines which are not related to a new generating facility.

In addition to the Pacific Intertie, Edison has ownership or entitlement in three 500 kV AC transmission lines in the Southwest. Through the pioneered utilization of these high voltage transmission facilities, Edison has maintained strong interconnections with all eleven western States and Canada for over a decade. These interconnections allowed Edison to import over 31% of its 1981 energy requirements, in addition to providing and receiving needed assistance during system emergencies or deficiencies.

These facilities have, however, required special reliability protection schemes to avoid the cascading outages reuslting from stability problems during system transients. Examples include:

1) Direct generator unit tripping due to the loss of transmission facilities or the occurrence of transmission induced subsynchronous resonance.

2) The utilization of transfer trip schemes whereby the loss of certain transmission facilities cause the automatic relaying of remote facilities to isolate the problem.

3) The use of automatic underfrequency load shedding which provides for the orderly dropping of bulk power substations and customer load in order to maintain a reasonable frequency level following the disconnection

of a major resource(s). This method also maintains the maximum amount of generation on-line to allow for the rapid restoration of the curtailed customers.

4) The automatic shedding of specified load to maintain minimum voltage levels during certain combinations of transmission outages.

Since the installation of automatic underfrequency load shedding equipment in the 1960's, there have been ten occasions (Attachemtn B) that it has been utilized with an average restoration time of less than 14 minutes. However, as a result of being interconnected, Edison has been able to withstand the loss of over 1,300 megawatts of load center generation, without the need to curtail customer load. Furthermore, Edison has imported over 1,700 megawatts of firm resources during system deficiencies.

During 1981, no customer outages resulted from the loss of generation. Distribution outages accounted for 95% of the total interruption time with the remaining 5% caused by transmission outages. The firm customer interruption time has averaged under 45 minutes and has not exceeded 88 minutes for the last 20 years as indicated by Attachment C. Weather related interruptions have accounted for 36% of the 20 year total, with equipment failures and third party mishaps ranking second and third.

Generation related interruptions are very infrequent on the Edison system as a result of the protection systems installed to isolate failed equipment or dampen the effects of other electrical system problems. The last generation caused interruption occurred in 1966 with the loss of Edison's largest generating station while carrying 1,465 megawatts, which represented over 25% of the load being served on that day.

Societal costs associated with the interruptions are minimal, particularly when you consider the short duration of the average interruption time. It is anticipated that this trend will continue since Southern California has less severe weather conditions and the Edison system has in place the previously mentioned protection methods to mitigate the occurrence and duration of outages. Furthermore, the inherently reliable transmission and subtransmission grid system serving the vast majority of our customers provides additional support and flexibility in serving the customer.

In 1979, as a result of an assessment of California's generating capacity levels, Edison and other major electric utilities in the state developed a capacity shortage contingency plan which provides for mutual support to help avert possible shortages of electric generation. Under this plan, aggressive public appeals and conservation efforts take place when statewide reserves drop to below 5%. Should reserve levels reach 1.5%, the deficient utility will commence the orderly manual curtailment of customer load. Edison has had a rotating load curtailment plan in place since early 1972. Fortunately, neither plan has had to be implemented.

In the area of system control, Edison has installed a comprehensive real-time bulk power data acquisition system in an an effort to more responsively monitor and control the electric system. As part of the system, eight remote processing centers are provided to facilitate decentralization during catastrophic emergencies. In addition, plans, procedures and systems are available for the relocation of basic dispatching functions should the need arise.

Within the generation area, numerous reliability and availability measures have been taken. Most notably are the:

1) Installation of jet peaking units in the 1960's to help serve the "needle peak" demands along with providing blackstart capability in the case of a massive system outage.

2) Provision of dual fuel burning capability at all oil/gas generating plants to help insure adequate supply of fuel energy.

3) Provision of multiple transmission lines emanating from generating facilities.

4) Installation of a comprehensive computerized generation maintenance scheduling system to help identify, plan and monitor maintenance activities to reduce forced outages while more efficiently performing the work.

Since the 1970's, Edison has placed a greater emphasis on the need to displace high cost oil and natural gas energy production by increased purchases, in conjunction with the replacement of aging load center oil fueled generation by renewable and alternative resources. These objectives increase the amount of generation remote to Edison's system with the inherent reduction in operating and control flexibility. Of further concern is the difficulty in receiving approval for new or additional transmission lines to reliably facilitate these additional imports.

The planned increase in renewable and alternative resources such as cogeneration, wind, solar and geothermal also creates other operating uncertainties, including:

1) The capacity value of these resources during peak load periods.

2) The maintenance requirements, particularly in the area of geothermal facilities which operate in a saline environment.

3) The ability of renewable and alternative resources to follow customer load changes.

4) The concern that cogeneration production is controlled more by the process requirements than by the needs of the electric utility.

Edison has also developed various load management programs and rate schedules unique to its own system load shape, in an effort to mitigate the effects of the "needle peak" demands. Among these programs are the:

1) Provision of an interruptible rate schedule whereby large customers designate an amount of load that can be curtailed by the utility.

2) Voluntary load reduction plan which enlists participation of large customers to voluntarily defer the use of non-essential loads during system deficiencies.

3) Residential air conditioning cycling program.

4) Demand subscription service whereby the customer selects a minimum level of service which will satisfy his needs during electric utility system deficiencies.

Finally, Edison believes the current comprehensive data collection and reporting systems in place by the NRC and NERC are adequate in tracking and responding to the type of generating unit status changes encountered. Further requirements may be needed in the future to monitor the performance of renewable and alternative resources, particularly since the operation and maintenance of a number of these resources is outside the direct control of the utility.

In conclusion, Edison currently has procedures and programs which will aid in the operation of the electrical system during energy and capacity deficiencies and system catastrophies. In addition, we have aggressively pursued methods to mitigate our fuel oil requirement and the effects of our needle peak demands.

Edison's future operational concerns stem from the increased difficulty to receive approval for new transmission/generation facilities and the uncertainties inherent in our effort to promote unconventional non-oil resources and offset existing oil/gas fired generation. The major areas of concern include:

- The operational uncertainty surrounding the performance of renewable/alternative resources.
- The inability to add generating capability in the load center.
- The operational uncertainty associated with the various load management programs.
- The increased emphasis on resources outside of Edison's service territory and direct control.
- The increasing age of existing generating facilities.
- The increased loading of existing transmission facilities.

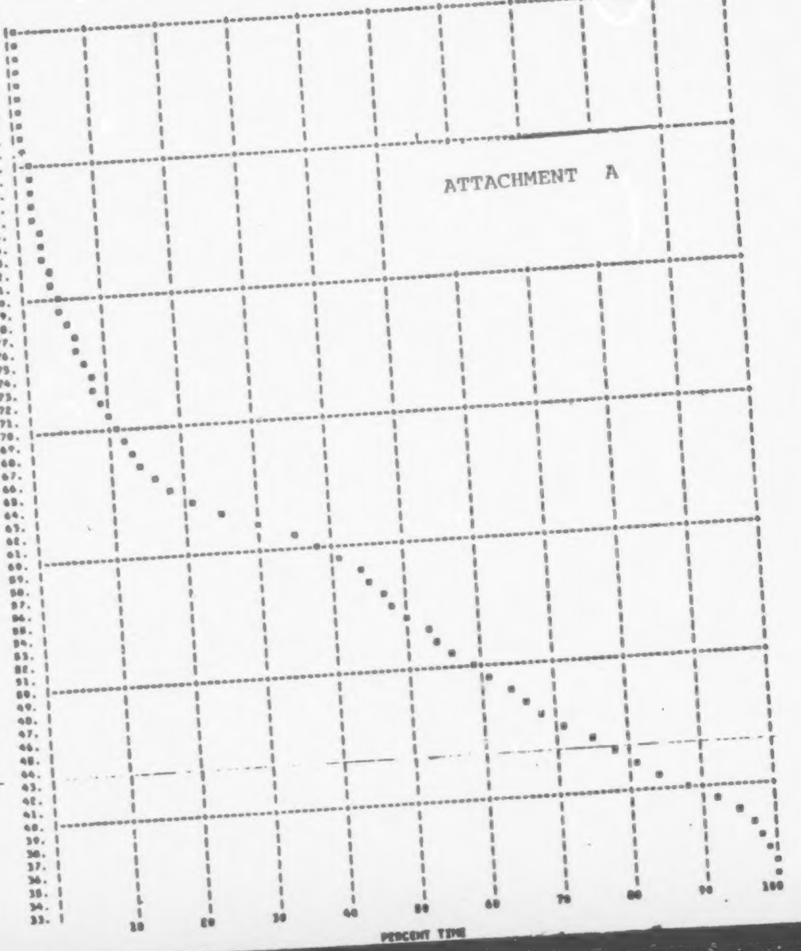
Because more of our additional resources will use unconventional methods of generation, with the attendant reduction in the proportion of total resources under the direct operational and maintenance control of Edison, we are entering an era of increased uncertainty.

LOAD DURATION CURVE

1981 HISTORICAL DATA

ATTACHMENT A

HOURS	PCT TIME	PCT. LOAD
1.	0.01	100.
2.	0.02	99.
4.	0.05	98.
8.	0.09	97.
12.	0.14	96.
15.	0.17	95.
19.	0.22	94.
26.	0.30	93.
34.	0.39	92.
40.	0.46	91.
47.	0.54	90.
56.	0.64	89.
75.	0.86	88.
93.	1.06	87.
119.	1.36	86.
143.	1.63	85.
176.	2.01	84.
213.	2.43	83.
251.	2.87	82.
300.	3.42	81.
344.	3.93	80.
390.	4.45	79.
442.	5.05	78.
498.	5.69	77.
566.	6.46	76.
612.	6.99	75.
660.	7.53	74.
731.	8.34	73.
804.	9.18	72.
866.	9.89	71.
944.	10.78	70.
1034.	11.80	69.
1117.	12.75	68.
1245.	14.21	67.
1395.	15.92	66.
1573.	17.96	65.
1852.	21.14	64.
2161.	24.67	63.
2645.	30.19	62.
3043.	34.74	61.
3330.	38.01	60.
3600.	41.10	59.
3827.	43.69	58.
3978.	45.41	57.
4081.	46.59	56.
4214.	48.11	55.
4376.	49.95	54.
4601.	52.52	53.
4768.	54.43	52.
4948.	56.48	51.
5139.	58.66	50.
5341.	60.97	49.
5519.	63.00	48.
5764.	65.80	47.
5990.	68.38	46.
6242.	71.26	45.
6544.	74.70	44.
6854.	78.24	43.
7068.	80.68	42.
7321.	83.57	41.
7678.	87.65	40.
8060.	92.01	39.
8289.	94.62	38.
8462.	96.60	37.
8608.	98.26	36.
8715.	99.49	35.
8754.	99.93	34.
8760.	100.00	33.



ATTACHMENT B

HISTORICAL EDISON LOAD SHEDDING
CAUSED BY MAJOR SYSTEM DISTURBANCES

DATE OF OCCURRENCE	LOAD SHED (MW)	RESTORATION TIME (MINS.)
July 19, 1966	1,291	3-27
May 21,1969	417	3-10
July 8, 1970	72	3
March 21, 1975	484	9-16
April 7, 1976	388	10-13
September 10, 1976	1,453	1-9
June 13, 1979	126	17
July 27, 1980	268	14
August 29, 1981	1,479	3-12
March 27, 1982	988	2-11

ATTACHMENT C

SOUTHERN CALIFORNIA EDISON COMPANY

AVERAGE CUSTOMER MINUTES OF INTERRUPTION PER CUSTOMER

YEAR	AVG. CUST. MINS. OF INTERRUPTION PER CUSTOMER	EEI FORMULA
1962	17.26	99.99691
1963	21.40	99.99622
1964	42.49	99.99134
1965	37.70	99.99393
1966	43.37	99.99220
1967	45.02	99.99143
1968	30.68	99.99416
1969	69.42	99.98679
1970	34.77	99.99338
1971	30.01	99.99429
1972	34.16	99.99351
1973	30.67	99.99416
1974	39.73	99.99244
1975	31.92	99.99392
1976	46.91	99.99107
1977	41.67	99.99207
1978	87.24	99.98340
1979	57.70	99.98902
1980	52.80	99.98995
1981	57.26	99.98911
20-YEAR AVG.	42.61	99.99189

*EEI Formula is the percentage of the ratio of the average customer-minutes of service to the total period minutes.

Mrs. **Bouquard**. Thank you very much, Mr. Fogarty. You have certainly given us excellent testimony.

I am fascinated with your controlling the customer's use of electricity to give greater reliability in other areas.

Mr. Yeager, to what extent do operations and maintenance affect the reliability of our generating plants?

Mr. **Yeager**. Our examination indicates that one could break up the reliability issues within the industry into two basic parts; the basic designed fabrication of the hardware itself and second, its operation and maintenance. New technology is not always the answer. The answer oftentimes is simply understanding the limits of the technology that you have and operating it within those limits. One of the things that we found is that powerplants today are often forced to operate outside the limits for which they were designed because of demands that were not foreseen at the time they were built.

For example, they may be going through what we would call cycling duty which puts tremendous thermal stresses on the components within the powerplant that can lead to premature failure and reduced longevity. It is one of the key areas that the industry is working on to achieve a better understanding of how to measure that effect of cycling and what the limitations are that one should live within.

Mrs. **Bouquard**. How would the introduction of a scrubber affect the operation of a coal-fired plant?

Mr. **Yeager**. Very much. Most of the scrubbers we see today were considered really as just add-on black boxes, hung on the back of the powerplant. The integrated design of the environmental control equipment, most especially a scrubber, directly affects the design of the powerplant. If you are going to achieve the reliability that you intend. They must be viewed as a system and put together as a system. That typically has not been the case.

Mrs. **Bouquard**. You have consistently reported R&D related to technology development. Do you think our Federal R&D ought to also include analysis of power system reliability factors?

Mr. **Yeager**. My feeling is that that is best left to the industry. I think where the Federal Government's role is in taking on some of the high risk, longer range development activities that will provide the foundation for improved reliabiity in the future. I think the operation of the power systems themselves—and the other gentlemen on the panel who are much closer to that than I am may want to comment—is really best handled by the industry. I think you pointed up very well, that the utility industry in this country continues to be the world leader in the operation of technology and in the reliability of its systems I think what the industry needs is the incentives, financial and so forth, to implement the results of its own research. I think it can do its own job best.

Mrs. **Bouquard**. How has the change in the Government funding and the Government's cooperation with EPRI affected your efforts? What needs to be cut out or what do we need to be moving on? In what direction should we be plowing ahead with our limited funds?

Mr. **Yeager**. About 2 months ago, I testified on that subject to the committee. I would summarize it by saying that the major impact is the almost overnight elimination of support for the development and demonstration of technology. We have worked closely with the industry and with DOE in a number of technologies, moving them logically through the development cycle to the point where they have good commercial potential. Now we risk dropping them at the point where demonstration is practical.

That really leaves the situation in chaos. In response the industry is moving rapidly with the cool-water project, for example, to pick up the pieces and move the demonstration ahead. We are similarly planning to do that with fluid bed combustion of coal. Unfortunately there are many technologies, perhaps not as dramatic, that will get lost in the shuffle because there is not the ability to move them forward.

Mrs. BOUQUARD. How far are we away from fluidized beds being competitive?

Mr. YEAGER. Well, my personal feeling is that it is very close. I might punctuate that by the fact that we are now beginning to operate with the Tennessee Valley Authority, as a result of Federal funding, a 20-megawatt electrical prototype of a utility fluid bed boiler.

As a result, we are now proceeding with the industry to build a 100- to 200-megawatt commercial full-scale power generating demonstration of fluidized bed combustion. That demonstration will be a powerplant designed to operate for 30 or more years as a normal power producing unit. We were very pleased to have about 12 utilities come back to us willing to build that privately at their expense with EPRI priority technical assistance together with some consideration for the incremental cost associated with a first of kind installation.

This means the demonstration will be primarily paid for by the utility industry. I think that is the real test of the commercial potential. The basis for its commercial readiness is the major investment made during the prototype phase by the Federal Government. If that hadn't been provided, the technology would be delayed at least 20 years.

Mrs. BOUQUARD. Is EPRI involved in our joint venture at Grimthorpe, England?

Mr. YEAGER. Yes; we are very pleased that the Grimthorpe project is continuing because we believe the pressurized, fluidized bed combustion option will have a lot of merit for our industry. Our involvement has been primarily on the technical side. We will now be participating financially there as well in the testing of advanced cleanup systems.

Mrs. BOUQUARD. Thank you very much.

Mr. Schultheis, I was very interested in your testimony that 70 percent of your generated capacity comes from imported oil. It certainly dismays me when I have to get votes to keep Clinch River going and I can't find many representatives from our area of the country who want to help us move ahead with the Clinch River breeder program.

Mr. SCHULTHEIS. I think the figure was 74 percent back in 1973. We have been fortunate to reduce it in New York—New England to about 45 percent currently, but that is still a very high figure, and without things like the new Millstone treaties and Sea Blocks and Shorehams and so forth, that number would not go down to the 20 percent we hoped for.

Mrs. BOUQUARD. Would you describe how purchases from Canada are reliable supplies? Do you consider it a firm commitment of do you think U.S. utilities could be cut off under certain conditions?

Mr. SCHULTHEIS. I guess I have been in an adversary relationship too long on the witness stand to answer questions by saying "It depends," but sometimes that is accurate.

The arrangements that we are negotiating today, both, I think, in New York and New England, are really not firm capacity arrangements.

In other words, they do come from surplus Canadian resources and, of course, they have made clear, and I think correctly so, that their own needs are going to have to come first.

In New England, at least, we are not planning to rely on these sources for capacity to meet reliability requirements. We are going to use them to reduce our dependence on oil and for a foreseeable period—that is, our interconnections will not be complete until 1986, and at least in a period into the late nineties, there will be, as a result of the ongoing construction of the James Bay facilities, surplus hydroenergy to their needs, so it will be, in that time frame, reasonably secure.

We anticipate—in fact, I was in Montreal yesterday—purusing with them the possibilities of purchasing on a firm basis, where there would be specific facilities that would be dedicated for our requirements and under those circumstances, the reliability would be comparable to the reliability of generating facilities, hydro generating facilities in the United States.

There is, of course, always an international boundary and a Government agency called the National Energy Board, and those do leave question marks that would have to be dealt with if we are to become dependent to a significant degree.

I have answered this question before by saying, if New England were dependent for 200,000 kilowatts, we wouldn't worry about those problems. If we were dependent on them for 3 million kilowatts, we would have to be concerned about it. It is a matter of degree.

Mrs. BOUQUARD. Do the utilities in your area cooperate to formulate reliability strategies?

Mr. SCHULTHEIS. Well, the utilities in New England are organized into the New England Power Pool, which has as one of the principal objectives the maintenance of a reliable bulk power supply system for New England, and the entire New England bulk power supply system is under a single dispatch, a single control center dispatch of the New England power exchange so that we both plan and operate New England as a single electric system and we plan the reliability criteria that are set forth by the Northeast Power Coordinating Council, where New England is one of the entities.

Mrs. BOUQUARD. Reliability studies have indicated there is need to improve the data, for additional data to improve the mathematical models. Do your utilities concur with this view? Are they willing to spend the money or man-hours to accumulate additional data?

Mr. SCHULTHEIS. I think the industry has, of course, recently set up the generation availability data system under the National

Electric Reliability Council, and while perhaps some of the data is going through some growing pains, I am certain that that will provide a consistent and good data base for the industry.

I had understood that Ron Niebo, who is in charge of that will be appearing here. But there are probably other issues. We have been involved in some work in trying to develop some far out total system reliability models and there will be a need to develop additional good data bases for transmission component system failure rates and so forth.

It is going forward. It started with NPCC and is now going forward under EPRI. EPRI is currently budgeting about $5 million for programing efforts to develop computer models for the interreliability area.

Mrs. BOUQUARD. Thank you very much.

Mr. Fogarty, I am interested in your demand subscription service. What are the limits to its widespread use?

Mr. FOGARTY. I think the first important element would be customer acceptance. If the customers don't use it or volunteer to use it, then it is not going to work, so our first job is to convince the customer that this interruption is really in their best interest.

Because by reducing our peak demand, we reduce our system costs and reduce the overall cost of electricity.

We have quite a public relations job to do, though, to convince some 100,000 of our customers to sign up for this sort of service.

We are trying to only sign up the high use customers. There is a residential customer interrupting device. We want to only put these devices on customers whose use of electricity exceeds 12,000 kilowatt-hours a year, so we want the high use customers so when we do interrupt, there is something that is interrupted and the load does drop.

It wouldn't do us much good to put it in an apartment house where perhaps there is a married couple living there both working, and if we tried to interrupt some load at 3:00 in the afternoon, there wouldn't be any load there to interrupt, so it has to be our larger users.

Unfortunately, these are the people who in most cases can best afford to pay for the electricity, so the economic incentive might not be enough. That is the first hurdle we have to overcome.

Mrs. BOUQUARD. Is there a cost factor?

Mr. FOGARTY. Yes. And in getting the people who can really afford to pay for the product interested enough in having the service discontinued or interrupted for a period of time.

The other problem is going to be with the hardware. We do not have well-developed hardware to do this job yet. When we put out our specifications, we had some 22 people respond initially. We had 11 bids that were qualified and that we evaluated.

We are down to four, now. But this equipment that is being proposed to us has a large degree of developmental work yet to do. I think we are going to have hardware problems, quite extensive hardware problems. We are not dealing with the people we have dealt with traditionally, the Sangamos, the Duncans, the GE's and the Westinghouses.

These are the meter manufacturers. It is a whole new breed. They are very innovative, they are relying heavily on electronics.

We think it is going to come but it is going to be forced and that is what we are doing by placing a large order. Of these 100,000 will be about $25 million, so it is a substantial order.

It is good piece of business, but the technology will have to be forced and we are going to have some problems with it.

Mrs. **Bouquard**. Powerplant design standardization has been mentioned quite often as having potential to increase plant reliability. Do you agree with this?

Mr. **Fogarty**. Well, I guess that I theoretically agree with it. From a practical standpoint, having been involved with it first some 30 years ago, I know the difficulties in getting powerplant standardization, even where it makes a great deal of sense.

The opportunities to deviate from the standard are numerous. First of all, the circulating water system or the cooling water system makes quite a bit of difference in the electrical output, and makes quite a bit of difference in the plant design.

In the nuclear area, where it makes even more sense to have a standard design, problems there arise immediately because of the seismic factors and these vary throughout the country.

They are particularly high in the California area, as you know. Tornado designs would not be appropriate in southern California. So, fundamentally, I agree that standardization is a good thing. From a practical standpoint, it seems like every time you get into a specific design, you immediately run into some persuasive reasons why you can't standardize.

Mrs. **Bouquard**. Such as seismic factors?

Mr. **Fogarty**. And the cooling water system. Those would be two things that make quite a bit of difference.

I mentioned earlier and would emphasize in coalfired plans the coal quality has a substantial impact on the plant reliability. It would also have a substantial impact on plant design.

For example, we have a plant, the Mojave plant, two units on a slurry pipeline. That plant, from the beginning, has had designed into it, because of the transport system, very, very high heat rates, 10,500 Btu's per kilowatt-hour, which is extremely high for a coal plant, but we get a very uniform coal quality delivered to us, but it has high moisture content, so that is a peculiar plant.

It could not be considered standard with anything else that exists in the industry.

Our Four Corners coal-fired plant in a similar fashion burns a very, very low Btu coal. In fact, the Btu value is so poor that the only reason we can burn it is that we make it remarkably uniform by putting it into blending piles, so that even though it is not very good coal, it is very consistent, and that way the plant operators can cope with the poorer coal quality and get reasonable reliability from the plant.

With coal variations, just in those two cases on our system, I think a standardized plant design again would be very difficult.

Mrs. **Bouquard**. In other words, you think it is a good idea but you don't think it is going to work?

Mr. **Fogarty**. That is right. I don't think it is going to happen. I haven't seen it happen in years, and perhaps I am pessimistic for that reason.

Mrs. **Bouquard**. Thank you very much.

Mr. Skeen?

Mr. **Skeen**. Thank you, Madam Chairman.

There may be low-grade coal, but there is plenty of it out there.

Mr. **Fogarty**. There certainly is.

Mr. **Skeen**. You mentioned several issues about transmission in your testimony. Would the use of superconductor storage technology help alleviate any problems?

Mr. **Fogarty**. I think certainly they would. Whether they would be a cost-effective solution, I don't know, but they would certainly alleviate the problem.

The situation now, when we have a break up of the AC intertie in the Northwest, the Bonneville System and up into B.C. Hydro, sitting there at very high frequency, perhaps approaching 61 Hertz; California and Southwest sitting at 59 Hertz, we are shedding load and they shedding generation.

And in many cases, cutting in breaking resistors to slow their system down.

Mr. **Skeen**. There is a very far-reaching and up-front program and was back in the seventies and all of a sudden it just fizzled out. I don't know what happened to the technology or whether or not the commercial generators had ever considered it or gotten to the point where it was commercially feasible.

Mr. **Fogarty**. I don't believe it ever got to that stage. Perhaps Mr. Yeager would like to comment on it, because I think EPRI was working on it at one time.

Mr. **Yeager**. EPRI is currently sponsoring the development of a superindustry generator technology by Westinghouse. This prototype facility will be installed on a TVA powerplant for demonstration this decade. We believe this technology provides both substantial efficiency and reliability advantages.

Mr. **Skeen**. Thank you very much.

Mrs. **Bouquard**. Thank you very much, Mr. Skeen.

Mr. Volkmer?

Mr. **Volkmer**. No questions, Madam Chairman.

Mrs. **Bouquard**. I thank you distinguished gentlemen for your excellent testimony and your valuable insight in our hearings.

We appreciate your being with us this morning.

Mrs. **Bouquard**. Welcome, gentlemen. We have your prepared testimony. You may feel free to read your entire testimony, summarize or proceed as you wish.

Mr. Reinschmidt?

STATEMENTS OF KENNETH REINSCHMIDT, VICE PRESIDENT, CONSULTING ENGINEER, STONE & WEBSTER ENGINEERING CORP., BOSTON, MASS.; ANDREW CAGNETTA, CHIEF MECHANICAL CONSULTING ENGINEER, EBASCO SERVICES, INC., NEW YORK, N.Y.; AND ROBERT SULLIVAN, DEPARTMENT OF ELECTRICAL ENGINEERING, UNIVERSITY OF FLORIDA, GAINESVILLE, FLA.

Mr. **Reinschmidt**. Thank you, Madam Chairman and members of the committee. My name is Kenneth Reinschmidt, and I am vice president and senior consulting engineer with the Stone & Webster Engineering Corp., and have been with that company for 7 years.

My responsibilities as manager of the consulting group include the oversight of engineering and economic studies by our consulting engineers and consulting economists in a variety of areas related to electric power generation and transmission.

I have been actively engaged in the analysis of powerplant performance and cost data during my employment with Stone & Webster and for several years prior to that. A brief résumé of my qualifications is attached to this statement.

The electric power system is one of the Nation's indispensable sources of energy. It supplies the high-quality energy to power an extraordinarily wide range of activities, from residential lighting to complex computers. Clearly, American society as we know it cannot function without reliable electricity.

The U.S. electric power system has been and continues to be very reliable; indeed, it is one of the most dependable of all large-scale systems. Electric generating stations are susceptible to all the problems of mechanical equipment, but adequate system reliability has been achieved by providing sufficient reserve margin to compensate for individual unit outages.

In addition to being reliable, electricity has also been economical. Electric rates, deflated by the Consumer Price Index to constant dollars per kilowatt-hour, fell steadily from 1932 to 1970. Even today, when there is so much concern about electricity costs, the average cost per kilowatt-hour, in constant dollars, is less than it was in any period prior to 1960.

The decade from 1965 to 1975 was a period of change in the electric industry. Generating units became much larger and more complex. Safety and environmental concerns required the addition of new equipment. The costs of new generating units, in constant dollars per kilowatt, which had been decreasing for many years, began to increase during this period. In order to achieve greater fuel efficiency and economies of scale in construction and operations, utilities continued to increase steam temperatures, pressures, and sizes of new generating units. The intended economies of scale and improved efficiencies were achieved, but the technical problems arising from the rapid scaling-up of boilers and turbines, plus higher pressures and temperatures, began to affect plant reliability.

The average forced outage rate for electric generating units, greater than 100 megawatts in size, rose from 3.7 percent in 1965 to 12.4 percent in 1979, using data reported by the North American Reliability Council. The average has since improved to 10.2 percent.

Conversely, the industry average equivalent availability, for units greater than 100 megawatts, fell from 87 percent in 1966 to 71 percent in 1976. Since 1976, equivalent availability has remained roughly level.

Using statistical methods, we examined generating units of all types and sizes for significant recent trends in reliability. Of 1,156 generating units greater than 100 megawatts, only 89 showed significant decreases in equivalent availability in the most recent 5 years. Almost as many units, 54, showed significant improvements in the same period and the vast majority, 1,013, showed no trend. The results for forced outage rates were very similar: 101 units showed significant increases, 77 had significant decreases, and 978 showed no significant change. These results are consistent with the observation that the utility-wide averages have remained stable since 1976.

In general, for any given fuel, a larger unit tends to have a better fuel efficiency but lower availability than a smaller unit. Larger units also tend to show greater effects of age. Aging effects vary with the type of fuel. Units of the same size burning gas, oil or coal tend to have almost identical availabilities when new, but oil-fired units show less decline with age than coal-fired units do. Gas-fired units show least aging of all. This performance might be expected, considering the characteristics of the different fuels, but must be regarded as of potential concern considering the national trend toward increased use of coal and the increasing age of generating units.

Since 1974, the electric utility industry has been faced with increasing costs, declining growth rates, low effective rates of return, and severe cash flow problems.

In view of these conditions, utilities reduced their capital investment in new generating capacity. If one divides utility capital expenditures on new generating units by the total installed capacity at the time, one finds that this rate of spending on new construction, in constant dollars, fell substantially after 1974.

In contrast, the average annual expenditures on capital improvements for existing units, in constant dollars per kilowatt of installed capacity, also fell in 1974 but have risen substantially since, and are much higher, even in constant dollars, than in any previous year. Planned outage hours, the number of hours per year that a unit is out of service for planned improvements, also have increased significantly for the past 15 years.

Moreover, the average annual utility expenditures on maintenance, in constant dollars per kilowatt of installed capacity, have risen continually throughout this period. The number of hours spent annually on maintenance has fluctuated around a level average value, and there is no correlation between maintenance hours spent and the forced outage rate.

The capacity factor for a generating unit is the ratio of the actual kilowatt-hours generated to the maximum amount the unit could have produced. By definition, the capacity factor must be lower than the unit's availability. The industry average capacity factor fell to 41 percent in 1978, but has been roughly level since then.

The trend in availability roughly parallels the trend in capacity factor, lagged by about a year. Consequently, the reserve factor, which is the difference between the availability and the capacity factor, has remained approximately level, on the average, from 1968 to 1979.

We expect this trend to continue in the future. Clearly, expenditures to increase unit availability are most necessary and effective in an environment of growing demand. An expanding national economy will cause capacity factors to rise again, leading to required increases in plant availability.

We believe that the reliability of units currently in service can in many cases be significantly improved, and the original designed-in level of availability restored. Our operations services division, for example, can assist utilities in the improvement of the reliability and fuel efficiency of their existing plants. Although major improvements are not obtained overnight, these reliability programs are highly cost-effective, with annual savings often exceeding the total cost of the program.

Availability improvement programs such as ours are based on basic principles of maintenance management, consisting both of corrective maintenance and preventive maintenance; spare parts management; and outage management, to accomplish the maximum amount of work during an outage and minimize its duration.

It is also our view, based on experience with larger plants, new systems and new equipment, that the reliability of new powerplants can be improved by standardization.

For this reason, Stone & Webster has developed a reference fossil powerplant for coal-fired stations of various sizes, with a design or target availability of 86 percent. This is equal to or better than the availabilities obtained 15 years ago for smaller, less complex plants. We have a similar program for a reference nuclear powerplant. The development of a standard design provides more opportunity for engineering reliability studies, and identification and selection of the most reliable equipment, than does the design of a single custom unit. The time and engineering costs for such studies would be prohibitive for a single unit design, but can be spread over many units with a standard design.

At Stone & Webster, feedback from operational plants, and design review of new plant designs by our operations services division, are two of our ongoing methods for improving the reliability of new plants.

By such means, reliable equipment is identified, plant layouts are modified to improve operations and maintenance accessibility, and plant systems are improved to increase reliability.

Where economically justified, reserve capacity can be provided by redundancy of equipment. For example, instead of a single pump of 100-percent capacity, the engineer may specify three pumps of 50-percent capacity each, giving a much higher probability of uninterrupted plant operation. Or, precipitators may be designed oversize to allow for in-service loss of performance. Such oversizing may only marginally increase the capital cost of the plant, and is cost-effective from the viewpoint of reliability and lifecycle costs. However, such investments in equipment to improve reliability may depend on the ability of the utility to recover the higher capital costs.

By application of these principles, we believe it is possible to improve the reliability of existing and future electric generating stations.

This concludes my prepared remarks, Madam Chairman. I should be pleased to respond to any questions from the committee. Thank you.

[The prepared statement of Mr. Reinschmidt follows:]

STATEMENT OF
KENNETH F. REINSCHMIDT
VICE PRESIDENT AND SENIOR CONSULTING ENGINEER
STONE & WEBSTER ENGINEERING CORPORATION

BEFORE THE
SUBCOMMITTEE ON ENERGY DEVELOPMENT AND
APPLICATIONS
AND THE
SUBCOMMITTEE ON ENERGY RESEARCH AND PRODUCTION
HOUSE COMMITTEE ON SCIENCE AND TECHNOLOGY

WASHINGTON, DC
June 8, 1982

Good morning, Mr. Chairman and members of the Committee. My name is Kenneth Reinschmidt. I am Vice President and Senior Consulting Engineer of the Stone & Webster Engineering Corporation and have been with Stone & Webster for seven years. My responsibilities as Manager of the Consulting Group include the oversight of engineering and economic studies by our Consulting Engineers and Consulting Economists in a variety of areas related to electric power generation and transmission. I have been actively engaged in the analysis of power plant performance and cost data during my employment with Stone & Webster and for several years prior to that. A brief resume of my qualifications is attached to this statement.

The electric power system is one of the nation's indispensable sources of energy. It supplies the high quality energy to power an extraordinarily wide range of activities, from residential lighting to complex computers. Clearly American society as we know it cannot function without reliable electricity.

The U. S. electric power system has been and continues to be very reliable; indeed, it is one of the most dependable of all large-scale systems. Electric generating stations are susceptible to all problems of mechanical equipment, but adequate system reliability has been achieved by providing sufficient reserve margin to compensate for individual unit outages.

In addition to being reliable, electricity has also been economical. Electric rates, deflated by the Consumer Price Index to constant dollars per kilowatt-hour, fell steadily from 1932 to 1970 (Figure 1). Even today, when there is so much concern about electricity costs, the average cost per kilowatt-hour, in constant dollars, is less than it was in any period prior to 1960.

The decade from 1965 to 1975 was a period of change in the electric industry. Generating units became much larger and more complex. Safety and environmental concerns required the addition of new equipment. The costs of new generating units, in constant dollars per kilowatt, which had been decreasing for many years, began to increase during this period (Figure 2). In order to achieve greater fuel efficiency and economies of scale in construction and operations, utilities continued to increase steam temperatures, pressures, and sizes of new generating units (Figure 3). The intended economies of scale and improved efficiencies were achieved, but the technical problems arising from the rapid scaling-up of boilers and turbines, plus higher pressures and temperatures, began to affect plant reliability.

The average forced outage rate for electric generating units, greater than 100 megawatts in size, rose from 3.7% in 1965 to 12.4% in 1979 (Figure 4). The average has since improved to 10.2%.

Conversely, the industry average equivalent availability, for units greater than 100 megawatts, fell from 87% in 1966 to 71% in 1976 (Figure 5). Since 1976 equivalent availability has remained roughly level.

Using statistical methods, we examined generating units of all types and sizes for significant recent trends in reliability. Of 1156 generating units greater than 100 megawatts, only 89 showed significant decreases in equivalent availability in the most recent five years. Almost as many units, 54, showed significant improvements in the same period and the vast majority, 1013, showed no trend. The results for forced outage rates were very similar: 101 units showed significant increases, 77 had significant decreases, and 978 showed no significant change. These results are consistent with the observation that the utility-wide averages have remained stable since 1976.

In general, for any given fuel, a larger unit tends to have a better fuel efficiency but lower availability than a smaller unit. Larger units also tend to show greater effects of age. Aging effects vary with the type of fuel. Units of the same size burning gas, oil, or coal tend to have almost identical availabilities when new, but oil-fired units show less decline with age than coal-fired units do. Gas-fired units show least aging of all (Figure 6). This performance might be expected, considering the characteristics of the different fuels, but must be regarded as of potential concern considering the national trend toward increased use of coal and the increasing age of generating units.

Since 1974, the electric utility industry has been faced with increasing costs, declining growth rates, low effective rates of return, and severe cash flow problems. In view of these conditions, utilities reduced their capital investment in new generating capacity. If one divides utility capital expenditures on new generating units by the total installed capacity at the time, one finds that this rate of spending on new construction, in constant dollars, fell substantially after 1974 (Figure 7).

In contrast, the average annual expenditures on capital improvements for existing units, in constant dollars per kilowatt of installed capacity, also fell in 1974 but have risen substantially since, and are much higher, even in constant dollars, than in any previous year (Figure 8). Planned outage hours, the number of hours per year that a unit is out of service for planned improvements, also have increased significantly for the past fifteen years (Figure 8).

Moreover, the average annual utility expenditures on maintenance, in constant dollars per kilowatt of installed capacity, have risen continually throughout this period (Figure 9). The number of hours spent annually on maintenance has fluctuated around a level average value, and there is no correlation between maintenance hours spent and the forced outage rate (Figure 9).

The capacity factor for a generating unit is the ratio of the actual kilowatt-hours generated to the maximum amount the unit could have produced. By definition, the capacity factor must be lower than the unit's availability. The industry average capacity factor fell to 41% in 1978 but has been roughly level since then (Figure 5). The trend in availability roughly parallels the trend in capacity factor, lagged by about a year. Consequently, the reserve factor, which is the difference between the availability and the capacity factor, has remained approximately level, on the average, from 1968 to 1979 (Figure 10).

We expect this trend to continue in the future. Clearly, expenditures to increase unit availabilty are most necessary and effective in an environment of growing demand. An expanding national economy will cause capacity factors to rise again, leading to required increases in plant availability.

We believe that the reliability of units currently in service can in many cases be significantly improved, and the original designed-in level of availability restored. Our Operations Services Division, for example, can assist utilities in the improvement of the reliability and fuel efficiency of their existing plants. Although major improvements are not obtained overnight, these reliability programs are highly cost-effective, with annual savings often exceeding the total cost of the program.

Availability improvement programs such as ours are based on basic principles of maintenance management, consisting of both corrective maintenance and preventive maintenance; spare parts management; and outage management, to accomplish the maximum amount of work during an outage and minimize its duration.

It is also our view, based on experience with larger plants, new systems and new equipment, that the reliability of new power plants can be improved by standardization. For this reason, Stone & Webster has developed a Reference Fossil Power Plant for coal-fired stations of various sizes, with a design or target availability of 86%. This is equal to or better than the availabilities obtained fifteen years ago for smaller, less complex plants. We have a similar program for a Reference Nuclear Power Plant. The development of a standard design provides more opportunity for engineering reliability studies, and identification and selection of the most reliable equipment, than does the design of a single custom unit. The time and engineering costs for such studies would be prohibitive for a single unit design, but can be spread over many units with a standard design.

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By application of these principles, we believe it is possible to improve the reliability of existing and future electric generating stations.

This concludes my prepared remarks, Mr. Chairman. I should be pleased to respond to any questions from the Committee. Thank you.

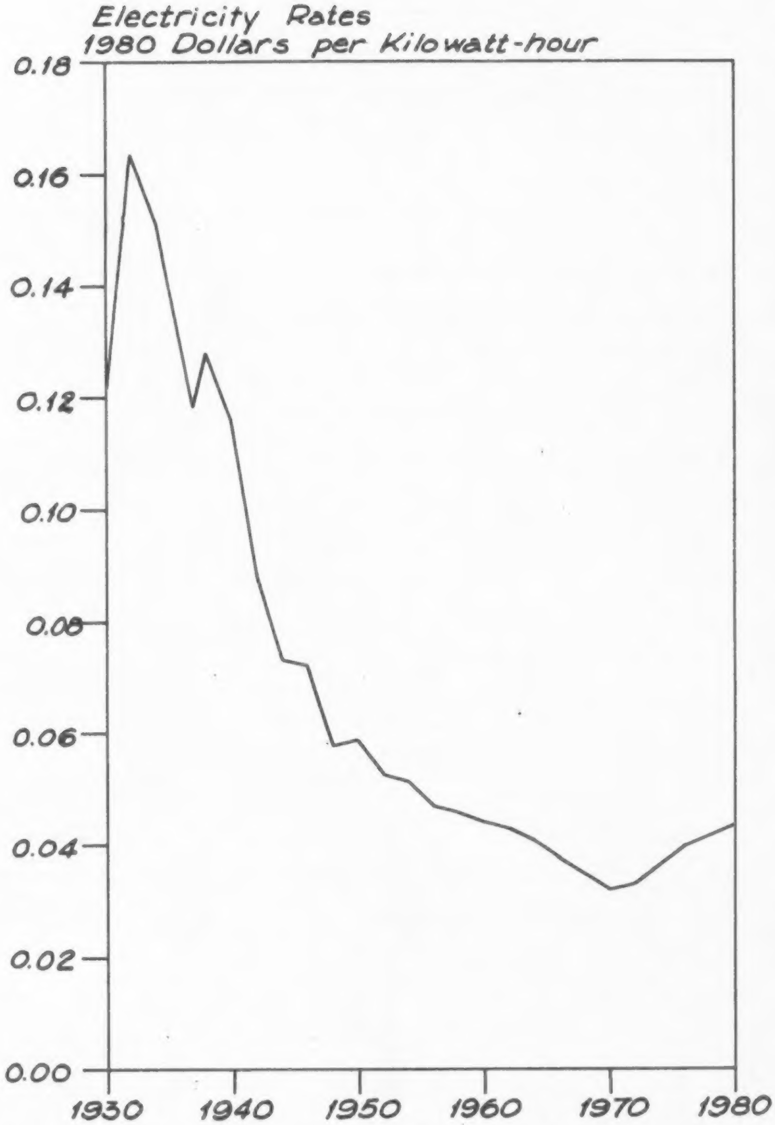


Figure 1. Average Costs of Electricity, 1980 Dollars per Kilowatt-hour

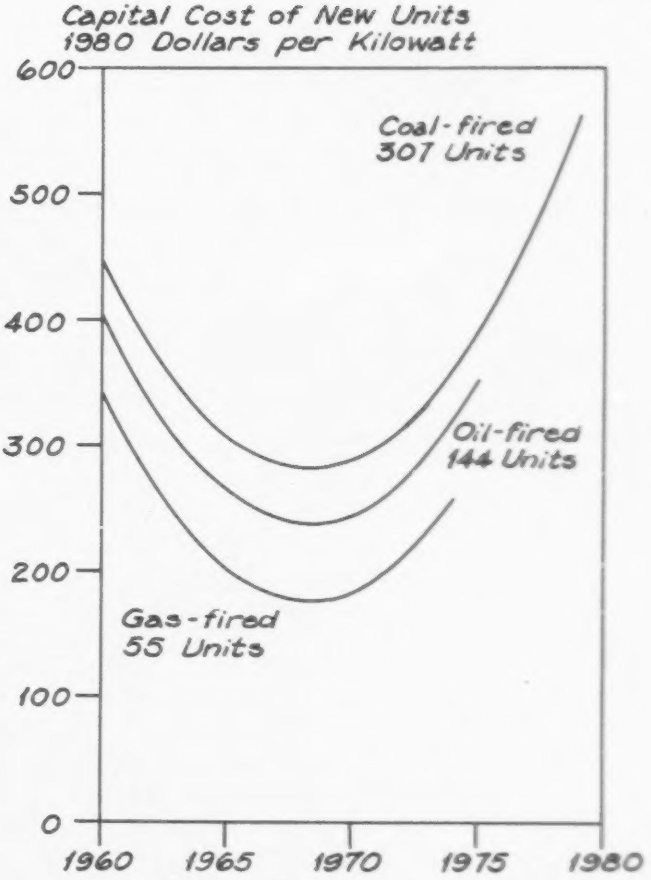


Figure 2. Average Capital Costs of New Units, 1980 Dollars per Kilowatt Based on Multivariate Regression Analysis

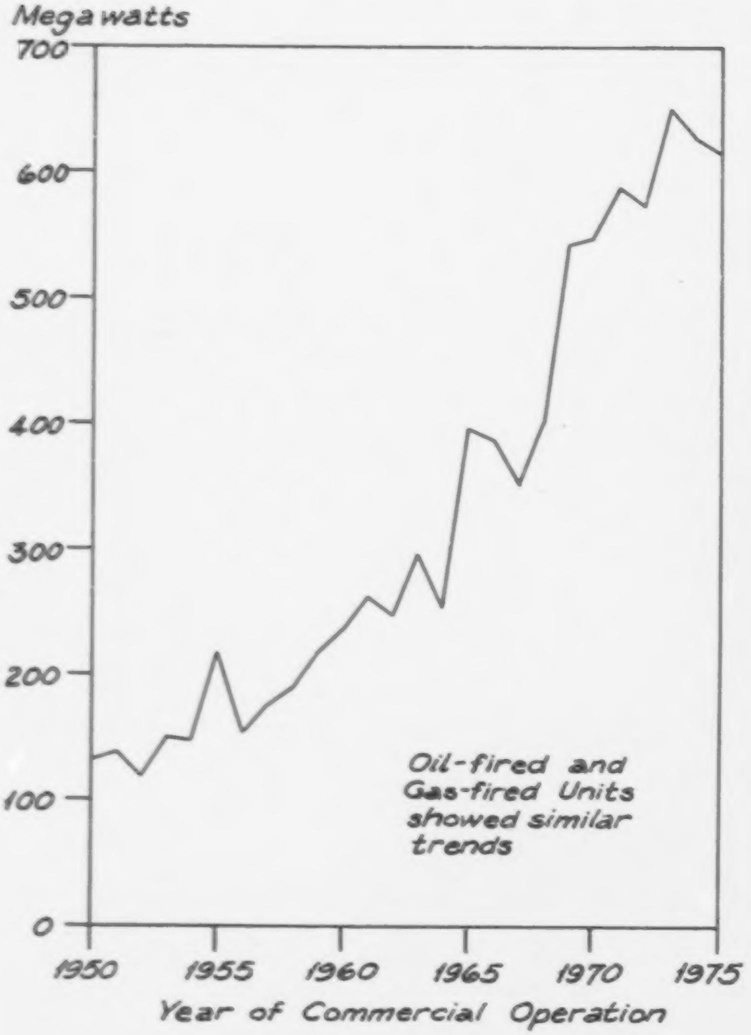


Figure 3. Average Size of New Major Coal-fired Units

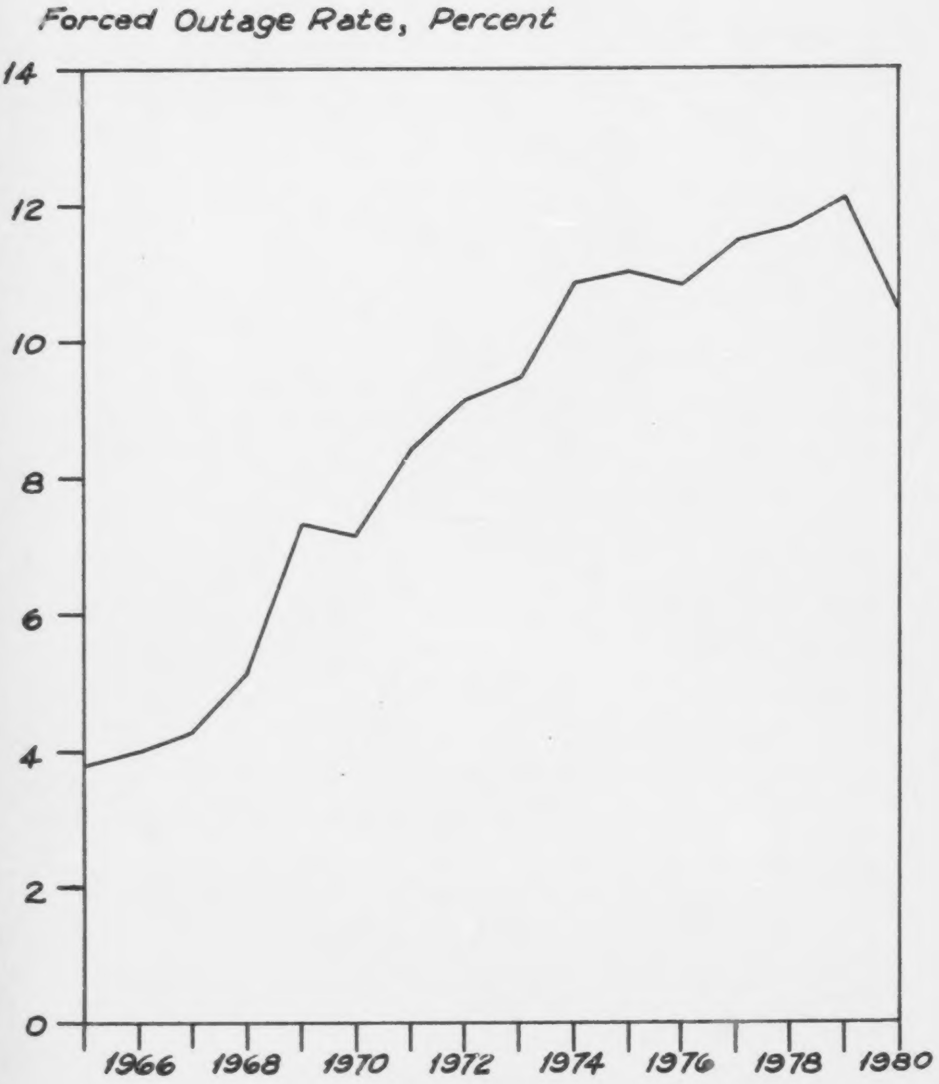


Figure 4. Average Annual Forced Outage Rate for All Major Units

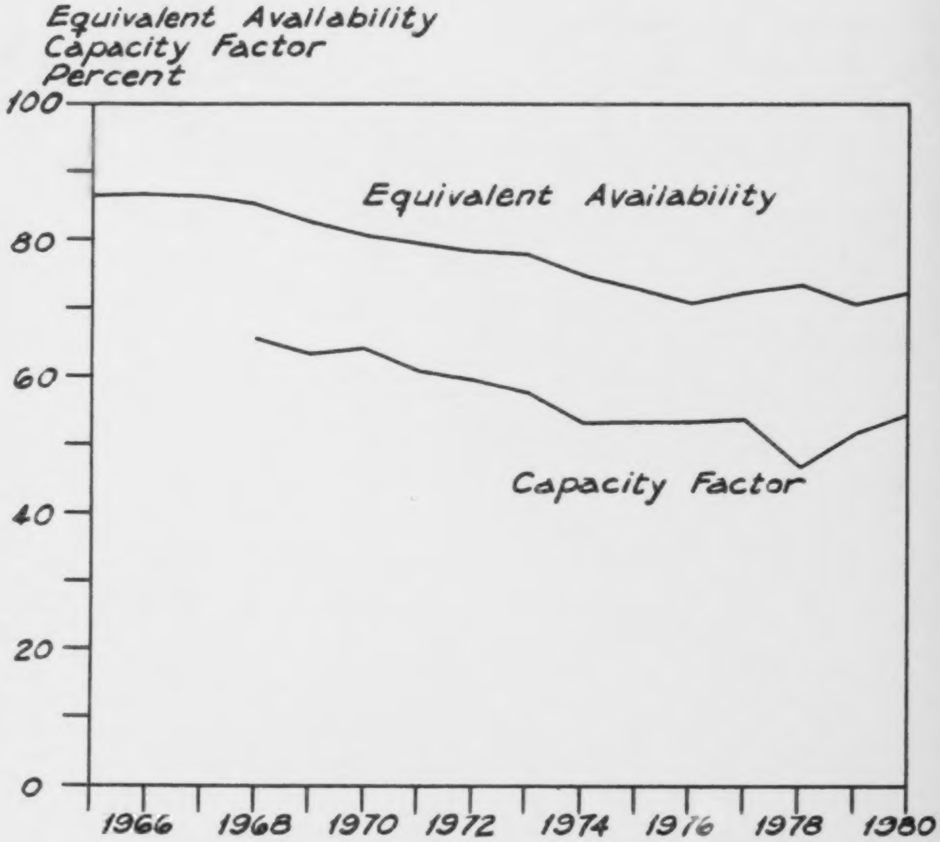


Figure 5. Average Equivalent Availability and Average Capacity Factor for All Major Units

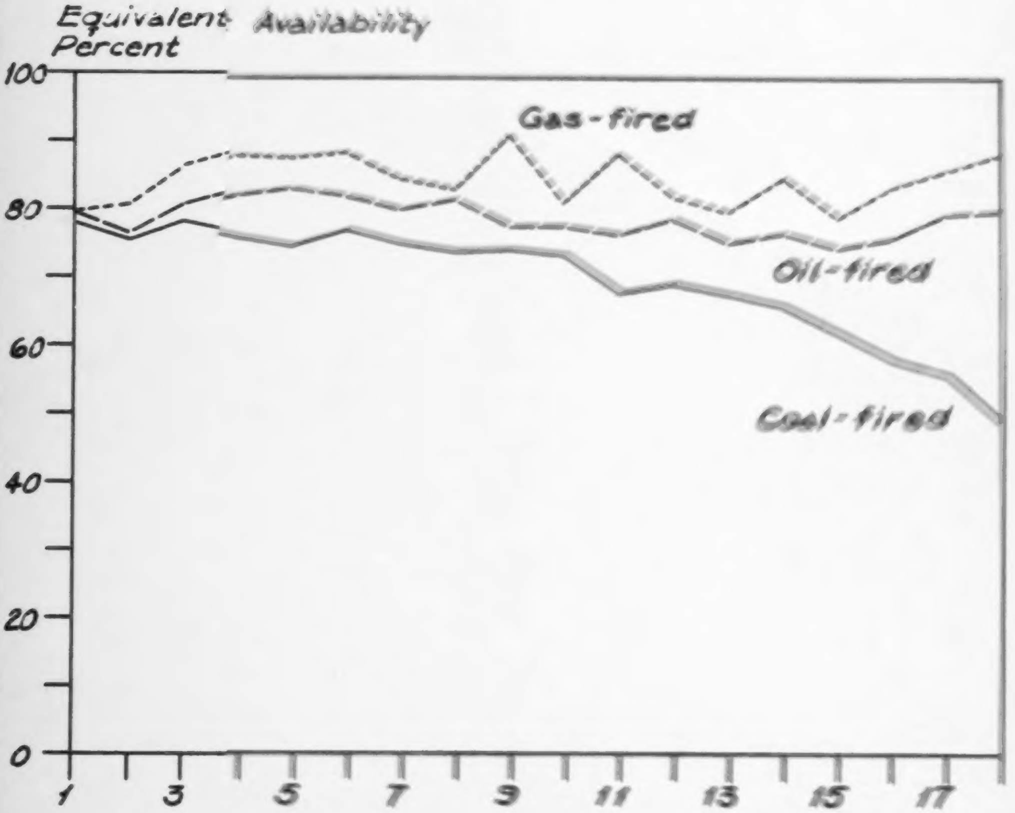


Figure 6. Equivalent Availability for Units in the 300 to 500 Megawatt Range versus Age in Years since First Commercial Operation

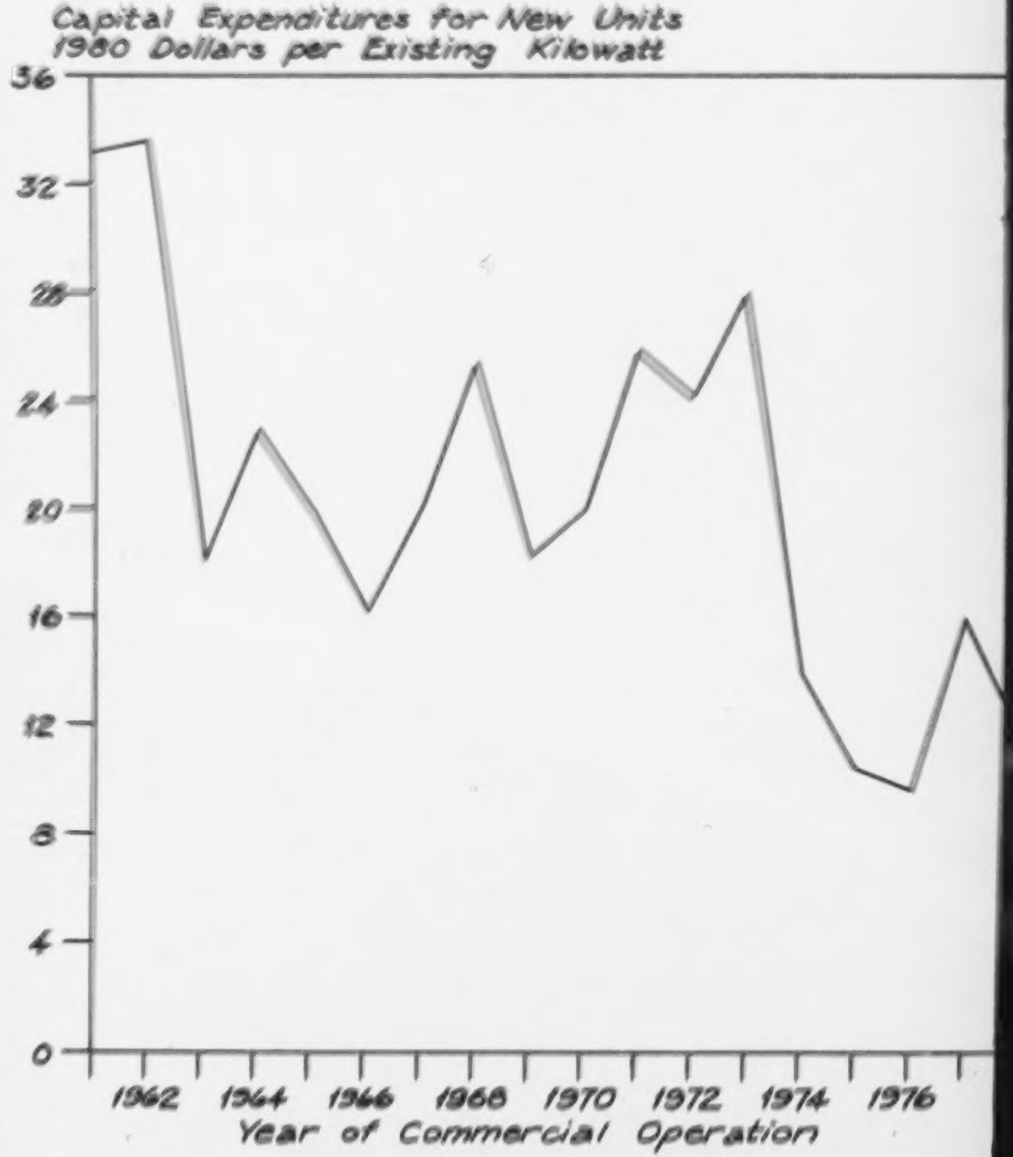


Figure 7. Average Annual Capital Expenditures for New Units, 1980 Dollars per Kilowatt of Existing Installed Capacity

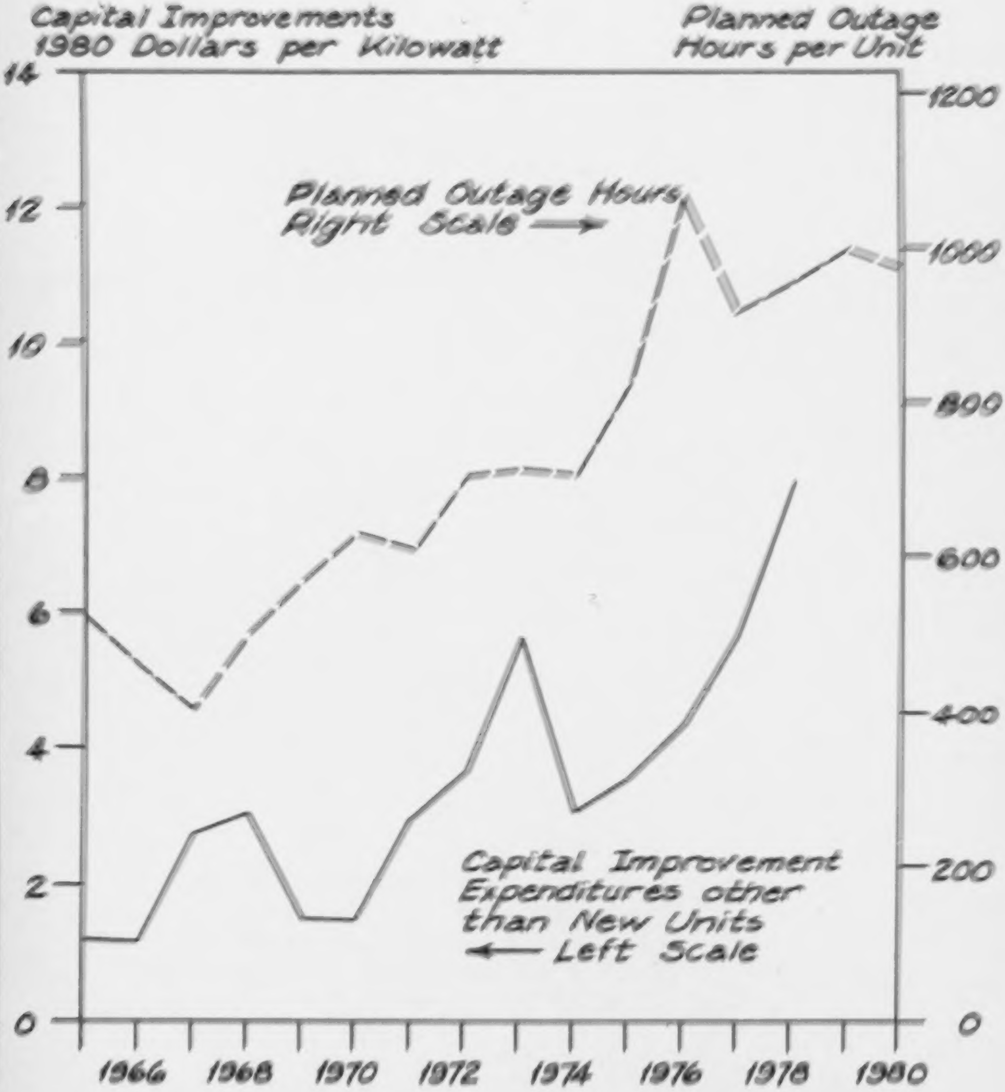


Figure 8. Average Annual Planned Outage Hours per Unit, All Major Units, and Average Annual Capital Improvement Expenditures, 1980 Dollars per Kilowatt of Installed Capacity

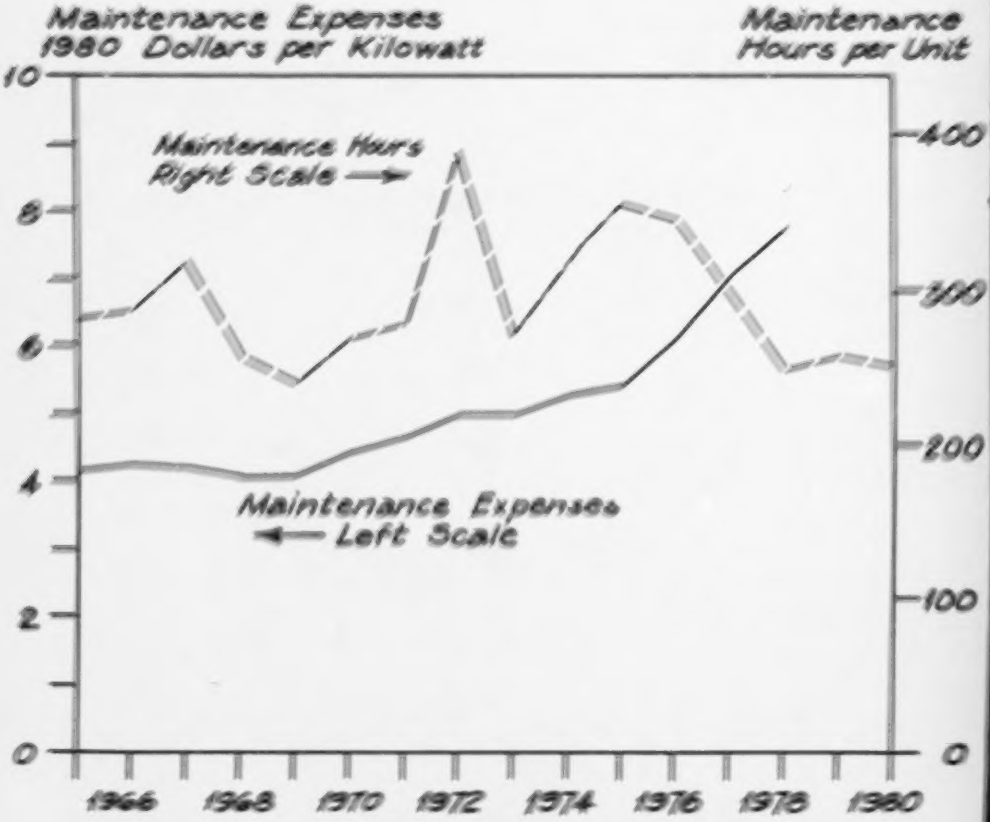


Figure 9. Average Annual Maintenance Hours per Unit, All Major Units, and Average Annual Maintenance Expenses, 1980 Dollars per Kilowatt of Installed Capacity

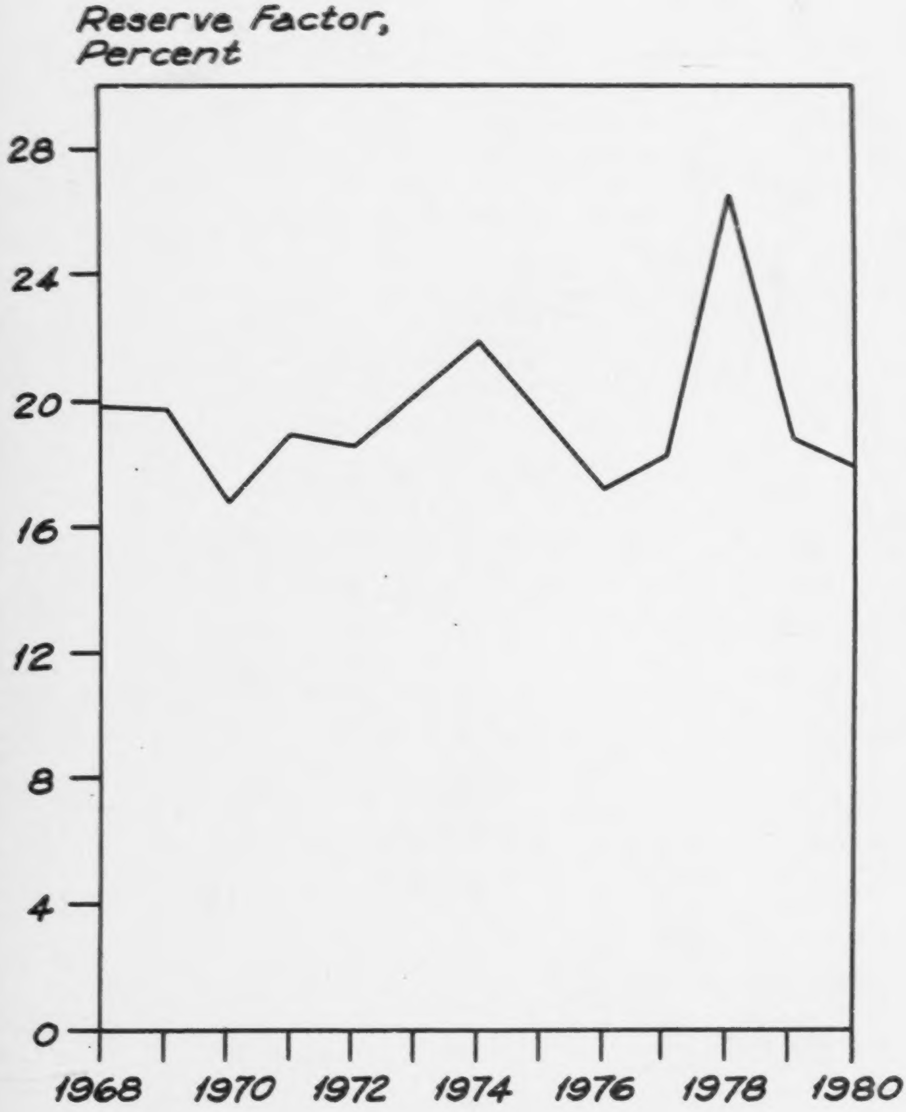


Figure 10. Average Annual Reserve Factor for All Major Units

KENNETH F. REINSCHMIDT

VICE PRESIDENT AND SENIOR
CONSULTING ENGINEER
MANAGER, CONSULTING GROUP

Education

PhD, Civil Engineering, MIT, 1965
SM, Civil Engineering, MIT, 1962
SB, Civil Engineering, MIT, 1960

Professional Associations

Operations Research Society of America
The Institute of Management Sciences
American Society of Civil Engineers
American Association for the Advancement of Science
Joint Committee on Tall Buildings
Tau Beta Pi
Sigma Xi
Chi Epsilon

Publications

Two books and thirty papers and articles on optimization, computer systems design, information analysis, construction management, structural design, building systems design, statistical analysis, and related topics.

Experience Summary

Dr. Reinschmidt has been associated with the Stone & Webster Engineering Corporation since 1975 as Consultant, Consulting Engineer, Senior Consulting Engineer, and Manager of the Consulting Group. Prior to joining Stone & Webster he had been an Associate Professor of Civil Engineering and Senior Research Associate at MIT. He served two years in the U. S. Army, which awarded him the Legion of Merit. At Stone & Webster, Dr. Reinschmidt has consulted on problems in such areas as construction management, seismic analysis of nuclear piping, project management, and probabilistic fracture mechanics. He has conducted statistical analyses of nuclear and fossil power plant costs, schedules, and operating experience, and has developed computer systems to optimize construction sites, to assess the economic risk of investment in synthetic fuel plants, to simulate engineering and design operations, to estimate the risk of cost overruns in construction, and to simulate construction productivity.

Consulting Areas of Interest

Econometric modelling
Structural analysis
Statistical analysis
Dynamic analysis
Optimization
Economics
Multivariate regression
Computer modelling
Systems analysis
Risk assessment.

Mrs. **Bouquard**. Thank you, Mr. Reinschmidt.

Mr. **Cagnetta**. Madam Chairman and members of the committee, I appreciate the opportunity to appear before you to discuss the subject of power system reliability. I am Andrew C. Cagnetta, Jr., chief mechanical consulting engineer for EBASCO Services Inc., New York, N.Y.

When we speak of power system reliability, we are actually referring to the reliability of its three distinct components: Power generation, bulk power transmission, and power distribution.

I will address this testimony to power generation reliability recognizing that others with appropriate expertise have already and will address the transmission and distribution system components.

Providing reliable electric generating stations, as well as reliable transmission and distribution systems, has been a long-standing goal of the electric utility industry. Despite our industry's success at providing a reliable electric system, today more than ever, utilities, manufacturers and engineering-constructors are striving to improve it.

The reason for this is rather fundamental and it is not a question of how much generating plant reliability we can afford. The financial impact of not achieving the highest possible reliability is substantial.

Due to continuing increases in plant investment requirements, the high cost of money, longer planning horizons due to regulatory delay and continually increasing costs of fuel and labor, the financial impact of reduced reliability is increasing each year.

Prior to the sixties utility growth was predictable and generating unit performance was stable because fossil units reached the 200-megawatt size in the midthirties and did not exceed this size until after 1955.

These units, many fourth and fifth generation have continued to demonstrate the highest availability of any unit size category.

The rapid increase in demand for electric energy during the sixties led industry into a time of rapid expansion of the number, size, and type of generating units. Units increased in size by a factor of 5, from the 200-megawatt units of the fifties to 1,000-megawatt and larger units in the sixties.

Accompanying the size change were technological changes regarding system design to improve generation efficiency as well as the use of nuclear power. These newer designs and larger units did not perform as well as the 200-megawatt units of the past, however, their economy of scale and efficiency improvements justified their construction during the sixties, when a financially healthy industry could invest in new units based on longer term project benefits.

Transition hit the industry in the early seventies, from an energy-affluent America to a new era with: One, environmental/safety regulations; two, fuel shortages and dependence on foreign oil; three, a generally weakening economy with high inflation, and, four, a dramatic reduction in load growth from levels predicted in the sixties.

This climate has driven up the cost of energy by a projected factor of 10 when looking at both coal and nuclear units authorized in 1969 for operation in 1976 to units authorized in 1980 for operation in the early nineties.

This transition has intensified the industry's efforts to reduce the need for capital for new generating units. Companies are entering into generation pooling agreements to reduce each company's generating capacity needs, instituting load management programs to levelize load requirements, assisting consumers toward conservation, studying the extension of the useful life of existing units while maintaining their productivity and intensifying reliability programs in order to avoid or delay new generating units.

Historical operating availability trends for coal units 400 megawatts and larger and all nuclear units from 1967 through 1980 are shown in my exhibit 1.

The data clearly demonstrates the declining trend between 1967 and 1972 as operating availability of coal-fired plants dropped from approximately 82 to 75 percent. This trend is the direct result of new population or larger sized units as well as the utilization of coals of poorer quality.

Forced outages in coal-fired plants are largely due to turbine generators and boilers, which have been responsible for over 90 percent of all forced outages with the boilers contributing more than 50 percent of these outages.

Since 1972, operating availability has stabilized around 75 percent, with the years 1978, 1979, and 1980 indicating an improving trend. This decline, leveling, and improving trends in availability of large coal units is an indication of the evolution of design maturity, similar to the industry's earlier experience with the 200-megawatt and smaller size units.

Nuclear units have also demonstrated a declining trend in operating availability, however, this is somewhat obscured by the limited number of plants in the early seventies, the impact of new designs and larger units in later years and outages caused by regulatory mandate including the TMI impact.

Past coal-fired unit experience has shown that the first several units of a new size and design will rarely achieve the reliability of a second or later generation unit of that same size class, which will be designed taking into account the design, operating and maintenance experience of the prototype units.

While this experience is common knowledge in the industry, during the sixties many utilities, of necessity, installed the first generation of a new size and design based upon system growth and anticipated economy of size.

More recently, this experience has stimulated interest in our industry to utilize a standardized approach to fossil plant designs.

This interest has grown because of the rapidly escalating costs for new facilities and the increased leadtime from initial project licensing activities through commercialization.

While this approach has its limitations; namely, the impact of coal quality on equipment and systems design as well as site-related variations, it does provide the basis for a systems approach to plant design using an established "reference" design and reliability enhancement based upon industry feedback.

Nuclear standardization was initiated in the early seventies, with the expectation that this approach would not only enhance safety and reliability, but would substantially reduce licensing duration, shorten design, enhance construction productivity and schedules, and substantially reduce investment costs.

Unfortunately, at this time, these efforts have been fruitless as our industry is no longer supporting this initiative in light of today's uncertainties. These uncertainties include:

One, lack of a clear mandate and support from Federal agencies that nuclear power must be expedited to provide an energy alternative to coal in an oil blackout policy in the decades ahead;

Two, no clear direction from the NRC on safety issues still under development and yet to be drafted that would impact standard designs.

In the decades ahead, it is apparent that the American electric utility industry will be strongly committed to coal-fired generating plants. A conventional pulverized coal-burning unit has the ability to provide the industry with all the advantages associated with an established technology.

The task of achieving high reliability is a complex effort. It requires sophisticated analysis of a myriad of variables related to plant design, specification, construction, operation, and maintenance. This includes the utility, the design engineers, manufacturers, and constructors.

In an effort to counteract an industrywide trend of declining unit availability, utilities, engineering firms, and manufacturers have formalized and expanded reliability programs.

Utilities have formalized plant upgrading programs for operating units utilizing available operating data. These programs are aimed at improving unit heat rates, investigating plant upgrading to obtain incremental generation, extending unit life and improving reliability.

Manufacturers of major equipment have also undertaken extensive reliability programs, recognizing the contribution of turbine generator and boiler outages to plant unavailability and forced outages.

These programs have resulted in the analysis of cause-and-effect relationships of outages and the ability to identify design/fabrication improvements to minimize or eliminate these outages in the future.

Utilities and industry, in many cases under the sponsorship of EPRI, have and are participating in more extensive investigations of coal quality and its impact on design and operation.

Engineering firms have also formalized reliability programs. These programs include:

One, the maintenance of coal-fired reference plant designs which are maintained based upon feedback from all industry sources and serve as a basis for new unit design as well as existing plant upgrading;

Two, utilizing more rigorous and comprehensive major equipment bid evaluations and purchasing strategies which focus on and emphasize reliability considerations;

Three, utilizing a formalized system design approach in plant designs which permits quantitative reliability analysis.

Four, encouraging and participating in the compilation of operating data following plant commercial operation.

Planning for new system additions is a major problem for the electric utility industry which may have long-term effects on system reliability. Despite the current reduced load growth, the average electric utility must still plan to satisfy a power demand that doubles approximately every 20 to 30 years.

Recognizing that leadtimes for a coal or nuclear facility are about 8 years and 12-plus years, respectively, meeting future growth requirements is still a monumental task.

This task is further complicated by the confusing environment confronting the licensing and construction of new generation, both fossil and nuclear.

In an era of unprecedented uncertainty, the electric utilities are battered on all sides. They must finance the capacity necessary to meet load demand in a tight money market with record high interest rates.

In addition, unstable fuel costs and the need to improve and maintain existing facilities are competing for whatever funds the utilities are able to obtain.

I believe the Government should take a hard look at how its actions, inactions or changes in priorities affect the electric utility industry. This is true for Federal and State levels of government.

Let's briefly review what has transpired with Federal policies. During the 1960's and early 1970's, the electric utility industry, with full Government support, pushed ahead to develop the nuclear option. After an enormous commitment of time and capital, the electric utility industry's nuclear effort stalled in the late 1970's, as a result of spiraling costs, unresolved safety issues and lack of Government support.

Nuclear costs rose because of the extended leadtimes required to license and construct each facility during a high inflationary economy.

Leadtimes extended because of concern over safety and environmental issues involved with nuclear generation and waste disposal. Many issues are still not resolved because of the reluctance of the Federal Government to pursue a consistent nuclear policy.

Consequently, those electric utilities with the largest commitment to nuclear power are currently in the poorest financial shape.

In addition, continuous racheting of new safety requirements on existing nuclear units establishes a continuous financial drain on the utility with respect to funding of the retrofit activities as well as the resultant loss of generating capacity and impact on reliability.

The Federal Government's policy on fossil fuels has also seriously affected the industry.

During the late 1960's and early 1970's, the electric utility industry converted many of its existing coal-fired units to oil because of rising governmental concerns over environmental issues.

In 1978, the Power Plant and Industrial Fuel Use Act was promulgated as part of the national energy plan to substitute coal for oil and natural gas in electric generation.

Therefore, a decade later, the electric utility industry was preparing to reconvert these same units back to coal. Three years later, under a new administration, the electric utility industry is allowed to consider fuel options based on a cost-benefit assessment.

These are but a few examples of how government caused uncertainty complicates generation planning. The electric utility industry requires a relatively stable framework to confidently integrate scheduled additions and improvements with load forecasts.

Historically, this has been the case. However, now with drawn-out licensing battles, uncertain rate relief and changing and oftentimes conflicting regulatory priorities, this has all changed.

Unless utilities are once more allowed to focus their efforts on maintaining and improving their electric system in a stable regulatory climate directed by consistent government policy, the system reliability can be expected to deteriorate.

Actions required: The electric utility industry has and will continue to balance various competing goals to assure that the public receives reliable, safe, and reasonably priced electric energy. A balance must be achieved between maximizing efficient use of available fuels, maximizing plant reliability, minimizing capital cost, and satisfying regulations.

Current economic/political conditions have focused the industry's attention toward aggressively pursuing existing station upgrading and life extension to postpone or eliminate the need for costly new nuclear or coal generating units, which will not provide an adequate return on equity.

However, our country's economic well-being depends on an adequate supply of energy, which, coupled with the Nation's goal to become energy independent, requires the continued installation of new generating facilities.

EBASCO believes the industry is presently restricted from providing a future adequate, reliable, and reasonable priced energy supply. In order to remove the restrictions, Government must take the following positive actions:

First, remove overlapping and conflicting Government regulations impeding the siting and timely completion of new generation.

Second, support timely and adequate rate relief so utilities can finance the upgrading of existing facilities as well as construction of new facilities. Ratemaking policies must recognize the present as well as future economic conditions to justify issues such as construction work in progress.

Public utility commissions cannot take the position that their primary function is to keep the present day cost of electricity as low as possible and ignore, one, the financial impact on the utilities; two, their responsibility for the future cost of energy; and, three, the adequacy and reliability of future electric power supply.

Third, conflicts that exist between environmental and safety goals must be balanced against energy needs and economic impacts to avoid significant investments for marginal environmental or safety gains.

Regarding nuclear units, Government must establish safety goals and determine "how safe is safe" to avoid the continued regulatory ratcheting of requirements which continues to drive the cost of operating and underconstruction nuclear facilities to unprecedented levels.

It is unreasonable for utilities, with nuclear units more than 50-percent complete, to still have unapproved designs which are subject to constant legal intervention by a host of special interest groups.

Fourth, establish time limitations for regulatory review to improve the accuracy of projections for unit upgrading, fuel conversions or new construction, as well as significantly reducing cost and schedule uncertainties.

Fifth, Government and the industry must educate the general public on the fundamentals of energy, such as the importance of energy to jobs, the relationship of energy to our standard of living, the viable energy technologies available and the advantages and disadvantages of these technologies.

Sixth, Government must identify and support the development of advanced technologies, such as solar energy, breeder reactors, and fusion power, which can produce significant quantities of electric energy to meet long-term needs.

The support required must avoid the stop-and-start scenarios of the past in order to provide industry with a clear indication of the Nation's future energy programs.

The benefits associated with improving the economic/political environment in which utilities conduct their business, by intensely supporting the actions I have outlined above, is paramount not only to improving the reliability of the electric power system, but to the financial viability of utilities, essential to our Nation's long-term growth and economic health.

Thank you for this opportunity to testify before this committee and permit me to note that EBASCO would be pleased to supply backup material and/or other information to support this testimony in your continued deliberation.

Mrs. BOUQUARD. Thank you very much.

[The prepared statement of Mr. Cagnetta follows:]

TESTIMONY OF

ANDREW C. CAGNETTA, JR.

CHIEF CONSULTING MECHANICAL ENGINEER
EBASCO SERVICES, INCORPORATED

TO

HOUSE COMMITTEE ON SCIENCE & TECHNOLOGY

SUBCOMMITTEES ON ENERGY DEVELOPMENT AND APPLICATIONS,

AND ENERGY RESEARCH AND PRODUCTION

JUNE 8, 1982

ANDREW C. CAGNETTA, JR.

EBASCO SERVICES, INC.

Chief Consulting Mechanical Engineer

EXPERIENCE SUMMARY

Registered Professional Engineer having over nineteen years of experience in conceptual and detail design engineering of fossil and nuclear-fueled electric generating stations with management level responsibilities. He has held positions of continuously increasing responsibility including Lead Mechanical Engineer, Project Engineer, Task Force Director, Project Manager, Assistant Chief Mechanical-Nuclear Engineer and Chief Consulting Mechanical Engineer.

His engineering and design experience includes participation on many projects involving coal, oil and gas fired power plants ranging in size from 300 MW to 1050 MW and nuclear plants of 600 to 960 MW.

Since 1978 he has been responsible for the Consulting Mechanical Engineering Department which performs services involving a broad range of technical and economic engineering services/studies for electrical utilities, energy intensive industries, research institutes and various governmental agencies. Power plant consultation includes services related to site selection, utility generation planning studies, plant conceptual design, plant systems/ equipment optimization studies and procurement including nuclear steam supply systems, turbine generator, boiler and air quality control systems. Services also include evaluation of advanced concepts in power plant design and energy utilization, fuel resources studies, fuel conversion and retrofit studies, cogeneration, utilization of refuse derived fuels, and studies involving emerging energy conversion processes such as fluidize bed combustion, geothermal, etc.

He has authored and/or presented many papers on the subject of fossil and nuclear plant comparative costs and reliability:

"Coal Quality - Designing a Power Plant for a Wide Range or Dedicated Coal Supply", 1981

"Nuclear Versus Fossil Plant Cost - Post TMI", 1980

"Comparative Costs of Alternate Coal Source Generating Plants", 1979

"Dramatic Changes in the Costs of Nuclear and Fossil Fueled Plants", 1978

"Replica and Reference Plant Approaches to Fossil Plant Standardization", 1977.

INTRODUCTION

MR CHAIRMAN AND MEMBERS OF THE COMMITTEE, I APPRECIATE THE OPPORTUNITY TO APPEAR BEFORE YOU TO DISCUSS THE SUBJECT OF POWER SYSTEM RELIABILITY. I AM ANDREW C. CAGNETTA, JR., CHIEF MECHANICAL CONSULTING ENGINEER FOR EBASCO SERVICES INCORPORATED, NEW YORK, NEW YORK. THIS TESTIMONY IS PRESENTED ON BEHALF OF EBASCO SERVICES, INCORPORATED.

WHEN WE SPEAK OF POWER SYSTEM RELIABILITY WE ARE ACTUALLY REFERRING TO THE RELIABILITY OF ITS THREE DISTINCT COMPONENTS: POWER GENERATION, BULK POWER TRANSMISSION AND POWER DISTRIBUTION. DUE TO TIME LIMITATIONS AND EBASCO'S PRIMARY ROLE AS PLANT ENGINEER/CONSTRUCTOR AND MY OWN AREA OF EXPERTISE, I WILL ADDRESS THIS TESTIMONY TO POWER GENERATION RELIABILITY RECOGNIZING THAT OTHERS WITH APPROPRIATE EXPERTISE WILL ADDRESS THE TRANSMISSION AND DISTRIBUTION SYSTEM COMPONENTS.

PROVIDING RELIABLE ELECTRIC GENERATING STATIONS, AS WELL AS RELIABLE TRANSMISSION AND DISTRIBUTION SYSTEMS, HAS BEEN A LONG STANDING GOAL OF THE ELECTRIC UTILITY INDUSTRY. DESPITE OUR INDUSTRY'S SUCCESS AT PROVIDING A RELIABLE ELECTRIC SYSTEM, TODAY MORE THAN EVER, UTILITIES, MANUFACTURERS AND ENGINEERING-CONSTRUCTORS ARE STRIVING TO IMPROVE IT. THE REASON FOR THIS IS RATHER FUNDAMENTAL AND IT IS NOT A QUESTION OF HOW MUCH GENERATING PLANT RELIABILITY WE CAN AFFORD. THE FINANCIAL IMPACT OF NOT ACHIEVING THE HIGHEST POSSIBLE RELIABILITY IS SUBSTANTIAL. DUE TO CONTINUING INCREASES IN PLANT INVESTMENT REQUIREMENTS, THE HIGH COST OF MONEY, LONGER PLANNING HORIZONS DUE TO REGULATORY DELAY AND CONTINUALLY INCREASING COSTS OF FUEL AND LABOR, THE FINANCIAL IMPACT OF REDUCED RELIABILITY IS INCREASING EACH YEAR.

GENERATION HISTORICAL TRENDS - COAL AND NUCLEAR UNITS RELIABILITY

PRIOR TO THE 1960'S UTILITY GROWTH WAS PREDICTABLE AND GENERATING UNIT PERFORMANCE WAS STABLE BECAUSE FOSSIL UNITS REACHED THE 200 MW SIZE IN THE MID-1930'S AND DID NOT EXCEED THIS SIZE UNTIL AFTER 1955. THESE UNITS, MANY FOURTH AND FIFTH GENERATION OF THE 200 MW OR SMALLER SIZE, HAVE CONTINUED TO DEMONSTRATE THE HIGHEST AVAILABILITY OF ANY UNIT SIZE CATEGORY. THESE UNITS GENERATED INEXPENSIVE AND PLENTIFUL ENERGY WHICH LED THE INDUSTRY INTO THE RAPID EXPANSION OF THE 1960'S.

OVER THE LAST TWO DECADES THE UTILITY INDUSTRY HAS NOT EXPERIENCED THE STABLE CLIMATE THAT EXISTED IN THE 1940'S AND 1950'S. IN FACT THE INDUSTRY HAS EXPERIENCED TWO DRASTICALLY DIFFERENT ECONOMIC/POLITICAL SCENARIOS. THE RAPID INCREASE IN DEMAND FOR ELECTRIC ENERGY DURING THE 1960'S LED INDUSTRY INTO A TIME OF RAPID EXPANSION OF THE NUMBER, SIZE AND TYPE OF GENERATING UNITS. TECHNOLOGY WAS CHANGING: UNITS INCREASED IN SIZE BY A FACTOR OF FIVE, FROM THE 200 MW UNITS OF THE 1950'S TO 1000 MW AND LARGER UNITS IN THE 1960'S. ACCOMPANYING THE SIZE CHANGE WERE TECHNOLOGICAL CHANGES REGARDING SYSTEM DESIGN TO IMPROVE GENERATION EFFICIENCY AS WELL AS THE USE OF NUCLEAR POWER. THESE NEWER DESIGNS AND LARGER UNITS DID NOT PERFORM AS WELL AS THE 200 MW UNITS OF THE PAST; HOWEVER THEIR ECONOMY OF SCALE AND EFFICIENCY IMPROVEMENTS JUSTIFIED THEIR CONSTRUCTION DURING THE 1960'S WHEN A FINANCIALLY HEALTHY INDUSTRY COULD INVEST IN NEW UNITS BASED ON LONGER TERM PROJECT BENEFITS.

TRANSITION HIT THE INDUSTRY IN THE EARLY 1970'S, FROM AN ENERGY AFFLUENT AMERICA TO A NEW ERA WITH: 1) ENVIRONMENTAL/SAFETY REGULATIONS, 2) FUEL SHORTAGES AND DEPENDENCE ON FOREIGN OIL, 3) A GENERALLY WEAKENING ECONOMY WITH HIGH INFLATION, AND 4) A DRAMATIC REDUCTION IN LOAD GROWTH FROM LEVELS PREDICTED IN THE 1960'S. THIS CLIMATE HAS DRIVEN UP THE COST OF ENERGY BY A PROJECTED FACTOR OF TEN WHEN BOTH COAL AND NUCLEAR UNITS AUTHORIZED IN 1969 FOR OPERATION IN 1976 ARE COMPARED TO UNITS AUTHORIZED IN 1980 FOR OPERATION IN THE EARLY 1990'S.

THIS TRANSITION HAS INTENSIFIED THE INDUSTRY'S EFFORTS TO REDUCE THE NEED FOR CAPITAL FOR NEW GENERATING UNITS. COMPANIES ARE MAKING GENERATION POOLING AGREEMENTS TO REDUCE EACH COMPANY'S GENERATING CAPACITY NEEDS, INSTITUTING LOAD MANAGEMENT PROGRAMS TO LEVELIZE LOAD REQUIREMENTS, ASSISTING CONSUMERS TOWARD CONSERVATION, STUDYING THE EXTENSION OF THE USEFUL LIFE OF EXISTING UNITS WHILE MAINTAINING THEIR PRODUCTIVITY AND INTENSIFYING RELIABILITY PROGRAMS IN ORDER TO AVOID OR DELAY NEW GENERATING UNITS.

HISTORICAL OPERATING AVAILABILITY TRENDS FOR COAL UNITS 400 MW AND LARGER AND ALL NUCLEAR UNITS FROM 1967 THROUGH 1980 ARE SHOWN IN EXHIBIT 1. I HAVE ONLY SELECTED 400 MW AND LARGER COAL UNITS AND NUCLEAR UNITS SINCE THESE APPEAR TO BE THE PRIMARY SIZES AND TYPE UNITS WE EXPECT WILL BE UTILIZED IN THE FUTURE. THE DATA CLEARLY DEMONSTRATES THE DECLINING TREND BETWEEN 1967 AND 1972 AS OPERATING AVAILABILITY OF COAL FIRED PLANTS DROPPED FROM APPROXIMATELY 82 PERCENT TO 75 PERCENT. THIS TREND IS THE DIRECT RESULT OF NEW POPULATION OF LARGER SIZED UNITS AS WELL AS THE UTILIZATION OF COALS OF POORER QUALITY. FORCED OUTAGES IN COAL FIRED PLANTS ARE LARGELY DUE TO TURBINE GENERATORS AND BOILERS, WHICH HAVE BEEN RESPONSIBLE FOR OVER 90 PERCENT OF ALL FORCED OUTAGES WITH THE BOILERS CONTRIBUTING MORE THAN 50 PERCENT OF THESE OUTAGES. SINCE 1972 OPERATING AVAILABILITY HAS STABILIZED AROUND 75 PERCENT WITH THE YEARS 1978, 1979 AND 1980 INDICATING AN IMPROVING TREND. THE DECLINE, LEVELING AND IMPROVING TRENDS IN AVAILABILITY OF LARGE COAL UNITS IS AN INDICATION OF THE EVOLUTION OF DESIGN MATURITY, SIMILAR TO THE INDUSTRY'S EARLIER EXPERIENCE WITH THE 200 MW AND SMALLER SIZE UNITS. NUCLEAR UNITS HAVE ALSO DEMONSTRATED A DECLINING TREND IN OPERATING AVAILABILITY, HOWEVER THIS IS SOMEWHAT OBSCURED BY THE LIMITED NUMBER OF PLANTS IN THE EARLY 1970'S, THE IMPACT OF NEW DESIGNS AND LARGER UNITS IN LATER YEARS AND OUTAGES CAUSED BY REGULATORY MANDATE INCLUDING THE T.M.I. IMPACT.

REPLICATION/STANDARDIZATION - IMPACT ON RELIABILITY

PAST COAL FIRED UNIT EXPERIENCE HAS SHOWN THAT THE FIRST SEVERAL UNITS OF A NEW SIZE AND DESIGN WILL RARELY ACHIEVE THE RELIABILITY OF A SECOND OR LATER GENERATION UNIT OF THAT SAME SIZE CLASS, WHICH WILL BE DESIGNED TAKING INTO ACCOUNT THE DESIGN, OPERATING AND MAINTENANCE EXPERIENCE OF THE PROTOTYPE UNITS. THE CONCEPT OF REPLICATION, THAT IS UTILIZING A MORE OR LESS COMPLETELY ENGINEERED AND DESIGNED PLANT WHICH MAY HAVE BEEN PREVIOUSLY CONSTRUCTED, HAS CLEARLY DEMONSTRATED THAT PLANTS INSTALLED BASED UPON THIS APPROACH WILL HAVE IMPROVED RELIABILITY; NAMELY, HIGHER OPERATING AVAILABILITY, LOWER FORCED OUTAGE RATES, ETC.

WHILE THIS EXPERIENCE IS COMMON KNOWLEDGE IN THE INDUSTRY, DURING THE 1960'S MANY UTILITIES, OF NECESSITY, INSTALLED THE FIRST GENERATION OF A NEW SIZE AND DESIGN BASED UPON SYSTEM GROWTH AND ANTICIPATED ECONOMY OF SIZE.

MORE RECENTLY, THIS EXPERIENCE HAS STIMULATED INTEREST IN OUR INDUSTRY TO UTILIZE A STANDARDIZED APPROACH TO FOSSIL PLANT DESIGNS, OFTEN REFERRED TO AS REFERENCE PLANTS, RATHER THAN THE TRADITIONAL USE OF CUSTOM DESIGNED PLANTS. THIS INTEREST HAS GROWN BECAUSE OF THE RAPIDLY ESCALATING COSTS FOR NEW FACILITIES AND THE INCREASED LEAD TIME FROM INITIAL PROJECT LICENSING ACTIVITIES THROUGH COMMERCIALIZATION. WHILE THIS APPROACH HAS ITS LIMITATIONS, NAMELY THE IMPACT OF COAL QUALITY ON EQUIPMENT AND SYSTEMS DESIGN AS WELL AS SITE RELATED VARIATIONS, IT DOES PROVIDE THE BASIS FOR A SYSTEMS APPROACH TO PLANT DESIGN USING AN ESTABLISHED "REFERENCE" DESIGN AND RELIABILITY ENHANCEMENT BASED UPON INDUSTRY FEEDBACK.

NUCLEAR STANDARDIZATION WAS INITIATED IN THE EARLY 1970'S, WITH THE EXPECTATION THAT THIS APPROACH WOULD NOT ONLY ENHANCE SAFETY AND RELIABILITY BUT WOULD SUBSTANTIALLY REDUCE LICENSING DURATION, SHORTEN DESIGN, ENHANCE CONSTRUCTION PRODUCTIVITY AND SCHEDULES AND SUBSTANTIALLY REDUCE INVESTMENT COSTS. UNFORTUNATELY, AT THIS TIME THESE EFFORTS HAVE BEEN FRUITLESS AS OUR INDUSTRY IS NO LONGER SUPPORTING THIS INITIATIVE IN LIGHT OF TODAY'S UNCERTAINTIES. THESE UNCERTAINTIES INCLUDE:

- LACK OF A CLEAR MANDATE AND SUPPORT FROM FEDERAL AGENCIES THAT NUCLEAR POWER MUST BE EXPEDITED TO PROVIDE AN ENERGY ALTERNATIVE TO COAL IN AN OIL BACKOUT POLICY IN THE DECADES AHEAD.

- NO CLEAR DIRECTION FROM THE NRC ON SAFETY ISSUES STILL UNDER DEVELOPMENT AND YET TO BE DRAFTED THAT WOULD IMPACT STANDARD DESIGNS.

MAXIMIZING UNIT RELIABILITY

IN THE DECADES AHEAD, IT IS APPARENT THAT THE AMERICAN ELECTRIC UTILITY INDUSTRY WILL BE STRONGLY COMMITTED TO COAL-FIRED GENERATING PLANTS. A CONVENTIONAL PULVERIZED COAL-BURNING UNIT HAS THE ABILITY TO PROVIDE THE INDUSTRY WITH ALL THE ADVANTAGES ASSOCIATED WITH AN ESTABLISHED TECHNOLOGY. HOWEVER, POOR RELIABILITY CAN RENDER THESE ADVANTAGES LESS EFFECTIVE.

THE COST OF POWER PRODUCTION IN THESE UNITS IS ON THE INCREASE DUE TO THE PRICE OF COAL, COSTS FOR EMISSIONS CONTROL AND THE EXPENSE OF HANDLING RESIDUAL SLUDGE AND FLYASH. MEANWHILE, EFFORTS TO PROTECT OPERATING INCOME FROM BEING ERODED BY THESE ESCALATING COSTS THROUGH RATE ADJUSTMENTS MEET WITH INCREASINGLY GREATER RESISTANCE. UNDER THESE CONDITIONS, OBTAINING HIGH RELIABILITY AND AVAILABILITY AT AN APPROPRIATE COST HAS BECOME ABSOLUTELY ESSENTIAL IN ORDER TO PREVENT THE LOSS OF FINANCIAL VIABILITY AND TO ENSURE AN ACCEPTABLE RETURN ON INVESTED CAPITAL.

THE TASK OF ACHIEVING HIGH RELIABILITY IS A COMPLEX EFFORT. IT REQUIRES SOPHISTICATED ANALYSIS OF A MYRIAD OF VARIABLES RELATED TO PLANT DESIGN, SPECIFICATION, CONSTRUCTION, OPERATION, AND MAINTENANCE. THIS INCLUDES THE UTILITY, THE DESIGN ENGINEERS, MANUFACTURERS AND CONSTRUCTORS. IN EACH SITUATION, A STRATEGY MUST BE DETERMINED THAT WILL PROVIDE THE MOST CONSISTENT OUTPUT OF ELECTRICITY, AS REQUIRED TO MEET DEMAND, AT THE LOWEST COST FOR NEW AS WELL AS EXISTING UNITS. IN AN EFFORT TO COUNTERACT AN INDUSTRY-WIDE TREND OF DECLINING UNIT AVAILABILITY, UTILITIES, ENGINEERING FIRMS AND MANUFACTURERS HAVE FORMALIZED AND EXPANDED RELIABILITY PROGRAMS.

UTILITIES HAVE FORMALIZED PLANT UPGRADING PROGRAMS FOR OPERATING UNITS UTILIZING AVAILABLE OPERATING DATA. THESE PROGRAMS ARE AIMED AT IMPROVING UNIT HEAT RATES, INVESTIGATING PLANT UPGRADING TO OBTAIN INCREMENTAL GENERATION, EXTENDING UNIT LIFE AND IMPROVING RELIABILITY.

MANUFACTURERS OF MAJOR EQUIPMENT HAVE ALSO UNDERTAKEN EXTENSIVE RELIABILITY PROGRAMS, RECOGNIZING THE CONTRIBUTION OF TURBINE GENERATOR AND BOILER OUTAGES TO PLANT UNAVAILABILITY AND FORCED OUTAGES. THESE PROGRAMS HAVE RESULTED IN THE ANALYSIS OF CAUSE AND EFFECT RELATIONSHIPS OF OUTAGES AND THE ABILITY TO IDENTIFY DESIGN/FABRICATION IMPROVEMENTS TO MINIMIZE OR ELIMINATE THESE OUTAGES IN THE FUTURE. BOILER RELIABILITY HAS BEEN SIGNIFICANTLY IMPACTED BY COAL QUALITY. AS PREVIOUSLY NOTED, UTILIZATION OF POORER QUALITY COALS THAN ASSUMED IN THE DESIGN OF UNITS, CONTRIBUTED TO THE DECLINING AVAILABILITY TREND NOTED IN EXHIBIT 1. UTILITIES AND INDUSTRY, IN MANY CASES UNDER THE SPONSORSHIP OF EPRI, HAVE AND ARE PARTICIPATING IN MORE EXTENSIVE INVESTIGATIONS OF COAL QUALITY AND ITS IMPACT ON DESIGN AND OPERATION.

ENGINEERING FIRMS HAVE ALSO FORMALIZED RELIABILITY PROGRAMS. THESE PROGRAMS INCLUDE:

- THE MAINTENANCE OF COAL FIRED REFERENCE PLANT DESIGNS WHICH ARE MAINTAINED BASED UPON FEEDBACK FROM ALL INDUSTRY SOURCES AND SERVE AS A BASIS FOR NEW UNIT DESIGN AS WELL AS EXISTING PLANT UPGRADING.

- UTILIZING MORE RIGOROUS AND COMPREHENSIVE MAJOR EQUIPMENT BID EVALUATIONS AND PURCHASING STRATEGIES WHICH FOCUS ON AND EMPHASIZE RELIABILITY CONSIDERATIONS. THIS EMPHASIS IS PARTICULARLY SIGNIFICANT FOR MAJOR EQUIPMENT SUCH AS TURBINE GENERATORS AND BOILERS IN COAL FIRED PLANTS OR NUCLEAR STEAM SUPPLY SYSTEMS IN NUCLEAR PLANTS, WHICH, COMBINED, CONTRIBUTE APPROXIMATELY 90 PERCENT OF ALL FORCED OUTAGES.

- UTILIZE A FORMALIZED SYSTEM DESIGN APPROACH IN PLANT DESIGNS WHICH PERMITS QUANTITATIVE RELIABILITY ANALYSIS.

- ENCOURAGING AND PARTICIPATING IN THE COMPILATION OF OPERATING DATA FOLLOWING PLANT COMMERCIAL OPERATION.

GENERATION PLANNING WITH TODAYS UNCERTAINTY

PLANNING FOR NEW SYSTEM ADDITIONS IS A MAJOR PROBLEM FOR THE ELECTRIC UTILITY INDUSTRY WHICH MAY HAVE LONG TERM AFFECTS ON SYSTEM RELIABILITY. DESPITE THE CURRENT REDUCED LOAD GROWTH, THE AVERAGE ELECTRIC UTILITY MUST STILL PLAN TO SATISFY A POWER DEMAND THAT DOUBLES APPROXIMATELY EVERY TWENTY YEARS. RECOGNIZING THAT LEAD TIMES FOR A COAL OR NUCLEAR FACILITY ARE ABOUT EIGHT YEARS AND TWELVE-PLUS YEARS, RESPECTIVELY, MEETING FUTURE GROWTH REQUIREMENTS IS STILL A MONUMENTAL TASK. THIS TASK IS FURTHER COMPLICATED BY THE CONFUSING ENVIRONMENT CONFRONTING THE LICENSING AND CONSTRUCTION OF NEW GENERATION - BOTH FOSSIL AND NUCLEAR.

IN AN ERA OF UNPRECEDENTED UNCERTAINTY, THE ELECTRIC UTILITIES ARE BATTERED ON ALL SIDES. THEY MUST FINANCE THE CAPACITY NECESSARY TO MEET LOAD DEMAND IN A TIGHT MONEY MARKET WITH RECORD HIGH INTEREST RATES. IN ADDITION, UNSTABLE FUEL COSTS AND THE NEED TO IMPROVE AND MAINTAIN EXISTING FACILITIES ARE COMPETING FOR WHATEVER FUNDS THE UTILITIES ARE ABLE TO OBTAIN. UNFORTUNATELY, GOVERNMENT POLICIES HAVE SERVED TO AGGRAVATE RATHER THAN IMPROVE THE UTILITIES' SITUATION. DIFFICULT PLANNING DECISIONS ARE MADE MORE DIFFICULT IN AN UNSTABLE PLANNING ENVIRONMENT. I BELIEVE THE GOVERNMENT SHOULD TAKE A HARD LOOK AT HOW ITS ACTIONS, INACTIONS OR CHANGES IN PRIORITIES AFFECT THE ELECTRIC UTILITY INDUSTRY. THIS IS TRUE FOR FEDERAL AND STATE LEVELS OF GOVERNMENT.

AT THE STATE LEVEL, THE ELECTRIC UTILITY INDUSTRY IS CONTINUOUSLY BAFFLED AT PUBLIC SERVICE COMMISSION (PSC) RATE SETTING POLICIES. RARELY DO ALLOWABLE RATE INCREASES PROVIDE ADEQUATE COMPENSATION FOR ELECTRIC UTILITY EXPENDITURES. UNDERSTANDABLY, THE PSC'S ARE CONCERNED ABOUT THE EFFECT OF ELECTRIC RATE INCREASES ON THE CONSUMER BUT OFTENTIMES THE PSC'S DECISIONS PLACE AN UNFAIR BURDEN ON THE UTILITY AND ITS INVESTORS. POLICIES SUCH AS NOT ALLOWING CONSTRUCTION WORK IN PROGRESS (CWIP) COSTS INTO THE RATE BASE FOR A LICENSED FACILITY WORK TO THE DETRIMENT OF THE UTILITY WITHOUT PROVIDING LONG TERM BENEFIT TO THE CONSUMER. IN ADDITION, SOME UTILITIES ARE NOW BEING INTRODUCED TO THE RELATIVELY NEW CONCEPT OF "TRENDING". INDIVIDUAL PSC'S ARE NOW EXPERIMENTING WITH THIS CONCEPT OF GRADUALLY ALLOWING NEW FACILITIES INTO THE RATE BASE. BY SPREADING OUT THE RATE RELIEF OVER TIME THE PSC'S ARE AVOIDING RATE "SPIKES" THAT WOULD RESULT IN ANTICIPATED CONSUMER PROTESTS. HOWEVER, BY DELAYING THE NECESSARY RATE RELIEF TO THE UTILITY, THE PSC'S ARE ALSO OVERTAXING THE ALREADY STRAINED FINANCIAL POSITION OF THE UTILITY. AFTER A DECADE OF EXTENSIVE CASH OUTLAYS TO LICENSE AND CONSTRUCT A GENERATING FACILITY IN ORDER TO SATISFY THE CONSUMERS' DEMAND FOR POWER, THE UTILITY MUST NOW PLAN TO FINANCE THE NEXT SYSTEM IMPROVEMENT OR ADDITION WITHOUT BENEFIT OF THE LAST ADDITION COMPLETELY IN THE RATE BASE.

IN CERTAIN CASES THE UTILITY MUST ALSO ACCEPT A DECISION THAT THE NEW GENERATING UNIT WILL NEVER BE ALLOWED INTO THE RATE BASE. THIS IS OCCURRING MORE FREQUENTLY AS PSC'S REVIEW UTILITY APPLICATIONS IN LIGHT OF REDUCED LOAD GROWTH. PSC'S ARE HOLDING ELECTRIC UTILITIES ACCOUNTABLE FOR SYSTEM LOAD PROJECTIONS MADE A DECADE AGO WHICH WERE BASED ON A HIGHER GROWTH SCENARIO. NEW GENERATION NOT SUPPORTED BY DEMAND AND NOT DELAYED DURING CONSTRUCTION IS BEING EXCLUDED FROM THE RATE BASE. ELECTRIC UTILITIES COULD POSSIBLY ACCEPT THIS IF IT WASN'T FOR THE FACT THAT THESE SAME PSC'S ALONG WITH OTHER GOVERNMENTAL AGENCIES, APPROVED THE ORIGINAL SYSTEM PLANNING STUDIES AND ENCOURAGED THE UTILITIES TO INVEST IN THIS NEW GENERATION.

AT THE FEDERAL LEVEL, THE IMPACT OF POLICY DECISION ON THE ELECTRIC UTILITY INDUSTRY IS EVEN MORE PROFOUND. DURING THE 1960'S AND EARLY 1970'S, THE ELECTRIC UTILITY INDUSTRY, WITH FULL GOVERNMENT SUPPORT, PUSHED AHEAD TO DEVELOP THE NUCLEAR OPTION. AFTER AN ENORMOUS COMMITTMENT OF TIME AND CAPITAL, THE ELECTRIC UTILITY INDUSTRY'S NUCLEAR EFFORT STALLED IN THE LATE 1970'S AS A RESULT OF SPIRALING COSTS, UNRESOLVED SAFETY ISSUES AND LACK OF GOVERNMENT SUPPORT. NUCLEAR COSTS ROSE BECAUSE OF THE EXTENDED LEAD TIMES REQUIRED TO LICENSE AND CONSTRUCT EACH FACILITY DURING A HIGH INFLATIONARY ECONOMY. LEAD TIMES EXTENDED BECAUSE OF CONCERN OVER SAFETY AND ENVIRONMENTAL ISSUES INVOLVED WITH NUCLEAR GENERATION AND WASTE DISPOSAL. MANY ISSUES ARE STILL NOT RESOLVED BECAUSE OF THE RELUCTANCE OF THE FEDERAL GOVERNMENT TO PURSUE A CONSISTENT NUCLEAR POLICY. CONSEQUENTLY, THOSE ELECTRIC UTILITIES WITH THE LARGEST COMMITTMENT TO NUCLEAR POWER ARE CURRENTLY IN THE POOREST FINANCIAL SHAPE. NUCLEAR UNIT DELAYS AND CANCELLATIONS ARE PREVALENT IN THE INDUSTRY, WITH THE ATTENDANT RISK THAT SUNK CAPITAL WILL NOT BE RECOVERED. IN ADDITION, CONTINUOUS RACHETING OF NEW SAFETY REQUIREMENTS ON EXISTING NUCLEAR UNITS ESTABLISHES A CONTINUOUS FINANCIAL DRAIN ON THE UTILITY WITH RESPECT TO FUNDING OF THE RETROFIT ACTIVITIES AS WELL AS THE RESULTANT LOSS OF GENERATING CAPACITY AND IMPACT ON RELIABILITY.

THE FEDERAL GOVERNMENT'S POLICY ON FOSSIL FUELS HAS ALSO SERIOUSLY AFFECTED THE INDUSTRY. DURING THE LATE 1960'S AND EARLY 1970'S, THE ELECTRIC UTILITY INDUSTRY CONVERTED MANY OF ITS EXISTING COAL FIRED UNITS TO OIL BECAUSE OF RISING GOVERNMENTAL CONCERNS OVER ENVIRONMENTAL ISSUES. IN 1978 THE POWER PLANT AND INDUSTRIAL FUEL USE ACT WAS PROMULGATED AS PART OF THE NATIONAL ENERGY PLAN TO SUBSTITUTE COAL FOR OIL AND NATURAL GAS IN ELECTRIC GENERATION. THEREFORE, A DECADE LATER, THE ELECTRIC UTILITY INDUSTRY WAS PREPARING TO RECONVERT THESE SAME UNITS BACK TO COAL. THREE YEARS LATER, UNDER A NEW ADMINISTRATION, THE ELECTRIC UTILITY INDUSTRY WAS ALLOWED TO CONSIDER FUEL OPTIONS BASED ON A COST BENEFIT ASSESSMENT.

THESE ARE BUT A FEW EXAMPLES OF HOW GOVERNMENT-CAUSED UNCERTAINTY COMPLICATES GENERATION PLANNING. THE ELECTRIC UTILITY INDUSTRY REQUIRES A RELATIVELY STABLE FRAMEWORK TO CONFIDENTLY INTEGRATE SCHEDULED ADDITIONS AND IMPROVEMENTS WITH LOAD FORECASTS. HISTORICALLY, THIS HAS BEEN THE CASE. HOWEVER, NOW WITH DRAWN-OUT LICENSING BATTLES, UNCERTAIN RATE RELIEF AND CHANGING AND OFTENTIMES CONFLICTING REGULATORY PRIORITIES, THIS HAS ALL CHANGED. UNLESS UTILITIES ARE ONCE MORE ALLOWED TO FOCUS THEIR EFFORTS ON MAINTAINING AND IMPROVING THEIR ELECTRIC SYSTEM IN A STABLE REGULATORY CLIMATE DIRECTED BY CONSISTENT GOVERNMENT POLICY, THE SYSTEM RELIABILITY CAN BE EXPECTED TO DETERIORATE.

ACTIONS REQUIRED

THE ELECTRIC UTILITY INDUSTRY HAS AND WILL CONTINUE TO BALANCE VARIOUS COMPETING GOALS TO ASSURE THAT THE PUBLIC RECEIVES RELIABLE, SAFE AND REASONABLY PRICED ELECTRIC ENERGY. A BALANCE MUST BE ACHIEVED BETWEEN MAXIMIZING EFFICENT USE OF AVAILABLE FUELS, MAXIMIZING PLANT RELIABILITY, MINIMIZING CAPITAL COST, AND SATISFYING REGULATIONS. CURRENT ECONOMIC/ POLITICAL CONDITIONS HAVE FOCUSED THE INDUSTRY'S ATTENTION TOWARD AGGRESSIVELY PURSUING EXISTING STATION UPGRADING AND LIFE EXTENSION TO POSTPONE OR ELIMINATE THE NEED FOR COSTLY NEW NUCLEAR OR COAL GENERATING UNITS.

OUR COUNTRY'S ECONOMIC WELL-BEING DEPENDS ON AN ADEQUATE SUPPLY OF ENERGY. COUPLED WITH THE NATION'S GOAL TO BECOME ENERGY INDEPENDENT, THIS REQUIRES THE CONTINUED INSTALLATION OF NEW GENERATING FACILITIES.

EBASCO BELIEVES THE INDUSTRY IS PRESENTLY RESTRICTED FROM PROVIDING A FUTURE WITH AN ADEQUATE, RELIABLE AND REASONABLE PRICED ENERGY SUPPLY. IN ORDER TO REMOVE THE RESTRICTIONS, GOVERNMENT MUST TAKE THE FOLLOWING POSITIVE ACTIONS:

1 - REMOVE OVERLAPPING AND CONFLICTING GOVERNMENT REGULATIONS IMPEDING THE SITING AND TIMELY COMPLETION OF NEW GENERATION.

2 - SUPPORT TIMELY AND ADEQUATE RATE RELIEF SO UTILITIES CAN FINANCE THE UPGRADING OF EXISTING FACILITIES AS WELL AS CONSTRUCTION OF NEW FACILITIES. RATE MAKING POLICIES MUST RECOGNIZE THE PRESENT AS WELL AS FUTURE ECONOMIC CONDITIONS TO JUSTIFY ISSUES SUCH AS CONSTRUCTION WORK IN PROGRESS.

PUBLIC UTILITY COMMISSIONS CAN NOT TAKE THE POSITION THAT THEIR PRIMARY FUNCTION IS TO KEEP THE PRESENT DAY COST OF ELECTRICITY AS LOW AS POSSIBLE AND IGNORE: 1) THE FINANCIAL IMPACT ON THE UTILITIES, 2) THEIR RESPONSIBILITY FOR THE FUTURE COST OF ENERGY, AND 3) THE ADEQUACY AND RELIABILITY OF FUTURE ELECTRIC POWER SUPPLY.

3 - CONFLICTS THAT EXIST BETWEEN ENVIRONMENTAL AND SAFETY GOALS MUST BE BALANCED AGAINST ENERGY NEEDS AND ECONOMIC IMPACTS TO AVOID SIGNIFICANT INVESTMENTS FOR MARGINAL ENVIRONMENTAL OR SAFETY GAINS.

REGARDING NUCLEAR UNITS, GOVERNMENT MUST ESTABLISH SAFETY GOALS AND DETERMINE "HOW SAFE IS SAFE" TO AVOID THE CONTINUED REGULATORY RATCHETING OF REQUIREMENTS WHICH CONTINUES TO DRIVE THE COST OF OPERATING AND UNDER CONSTRUCTION NUCLEAR FACILITIES TO UNPRECEDENTED LEVELS. IT IS UNREASONABLE FOR UTILITIES, WITH NUCLEAR UNITS MORE THAN 50 PERCENT COMPLETE, TO STILL HAVE UNAPPROVED DESIGNS WHICH ARE SUBJECT TO CONSTANT LEGAL INTERVENTION BY A HOST OF SPECIAL INTEREST GROUPS.

4 - ESTABLISH TIME LIMITATIONS FOR REGULATORY REVIEW TO IMPROVE THE ACCURACY OF PROJECTIONS FOR UNIT UPGRADING, FUEL CONVERSIONS OR NEW CONSTRUCTION, AS WELL AS SIGNIFICANTLY REDUCING COST AND SCHEDULE UNCERTAINTIES. REGULATORY AGENCIES MUST RECOGNIZE THE DIFFICULTIES CAUSED BY THE TIME NEEDED TO OBTAIN APPROVALS AND RE-DIRECT THEIR REGULATORY EMPHASIS TO MEET ENVIRONMENTAL AND SAFETY GOALS WHILE MINIMIZING COST AND OPERATING FLEXIBILITY IMPACTS ON THE UTILITIES.

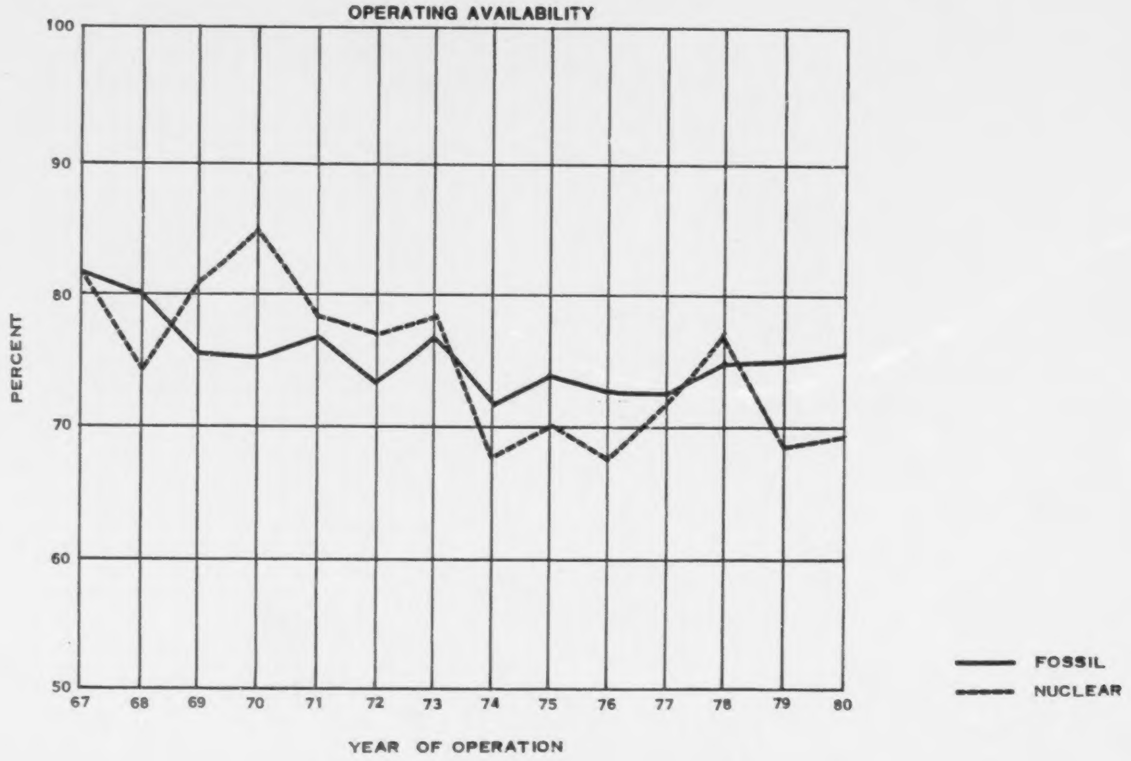
5 - GOVERNMENT AND THE INDUSTRY MUST EDUCATE THE GENERAL PUBLIC ON THE FUNDAMENTALS OF ENERGY: SUCH AS, THE IMPORTANCE OF ENERGY TO JOBS, THE RELATIONSHIP OF ENERGY TO OUR STANDARD OF LIVING, THE VIABLE ENERGY TECHNOLOGIES AVAILABLE AND THE ADVANTAGES AND DISADVANTAGES OF THESE TECHNOLOGIES.

6 - GOVERNMENT MUST IDENTIFY AND SUPPORT THE DEVELOPMENT OF ADVANCED TECHNOLOGIES, SUCH AS SOLAR ENERGY, BREEDER REACTORS AND FUSION POWER, WHICH CAN PRODUCE SIGNIFICANT QUANTITIES OF ELECTRIC ENERGY TO MEET LONG TERM NEEDS. THE SUPPORT REQUIRED MUST AVOID THE STOP AND START SCENERIOS OF THE PAST IN ORDER TO PROVIDE INDUSTRY WITH A CLEAR INDICATION OF THE NATION'S FUTURE ENERGY PROGRAMS. THE MOST RECENT EXAMPLE OF GOVERNMENT'S CHANGING DIRECTION OR PRIORITIES IS THE CUTBACKS IN SOLAR ENERGY FUNDING FOR R & D PROGRAMS UNDER THE DIRECTION OF VARIOUS UTILITITES.

THE BENEFITS ASSOCIATED WITH IMPROVING THE ECONOMIC/POLITICAL ENVIRONMENT IN WHICH UTILITIES CONDUCT THEIR BUSINESS, BY INTENSELY SUPPORTING THE ACTIONS I HAVE OUTLINED ABOVE, IS PARAMOUNT NOT ONLY TO IMPROVING THE RELIABILITY OF THE ELECTRIC POWER SYSTEM, BUT TO THE FINANCIAL VIABILITY OF UTILITIES, ESSENTIAL TO OUR NATION'S LONG TERM GROWTH AND ECONOMIC HEALTH.

COMPARISON OF FOSSIL COAL-FIRED UNITS 400MW AND ABOVE TO ALL NUCLEAR UNITS

UNIT YEAR AVERAGES
1967-1980



Mr. **Sullivan**. Madam Chairman, and other committee members, my name is Bob Sullivan, and I am a professor of electrical engineering at the University of Florida.

Since this is my first time before this joint committee, I would like to express my appreciation for having the opportunity to be here today, and, of course, I hope my testimony proves to be useful in shedding some light on where we should place our research dollars in addressing the problems of power system reliability.

Mrs. **Bouquard**. We are happy to have you here today.

Mr. **Sullivan**. Thank you.

I would like to begin my testimony by quoting from a technical paper written by Mr. S. M. Dean:

> One of the really difficult problems faced by those responsible for planning of electric supply systems is that of deciding how far they are justified in increasing the investment in their properties to improve system reliability. While the problem is not at all new in the industry, it has nevertheless taken on greatly increased significance in the last few years.

In some sense, this quote captures the spirit of much of the discussion being presented in these hearings; yet Mr. Dean's paper appeared in 1938.

Some 44 years later, it is interesting to find that the statement is even more appropriate. In fact, the thrust of the National Electric Reliability Study, in which I participated, was directed toward this exact issue.

We have made progress in addressing the issue of cost-effective reliability, but the progress has evolved along many fronts.

Briefly, the research community and industry have attacked the issue from the perspective of the individual systems that comprise the electric supply.

Further, two very different theoretical approaches have been employed. One approach simulates system operation over a given time interval and investigates system performance in the face of a variety of contingencies.

The other approach is more analytical and incorporates the random behavior of system components. Significant progress has been made in developing both simulation and analytical tools for planning generation and distribution system expansions, but less progress has been realized in developing transmission system analysis tools that explicitly incorporate system design parameters and operational procedures.

Because of the structural and operational complexity of the transmission system, reliability assessments are usually restricted to deterministic simulations of system performance.

Although we have refined our simulation capability tremendously over the years, current simulation tools rarely produce an overall index of performance that can be used to assess the cost effectiveness of the reliability of the system as seen by consumers.

Recent new fronts have developed because of the intense interest in the cost effective reliability issue in the electric utility industry. In particular, much more emphasis is being placed on advanced system operation than ever before as a means of achieving cost-effective reliability.

Security dispatch concepts are being routinely implemented to avoid operationally induced interruptions. Further, recognition that all interruptions cannot be avoided at a reasonable cost has produced keen interest in advanced restoration procedures.

Interruptions statistics suggest that uncoordinated restoration procedures can actually aggravate the severity of interruptions. In summary, we have made progress, but we still lack the systems technology to adequately address the concerns expressed by Mr. S. M. Dean's 1938 statement.

How effective have we been in creating a reliable power supply for the Nation using the planning tools developed over the years? The answer to this question based on recent rather incomplete statistics of eight utilities surveyed by DOE indicates that from 1974 to 1979 each customer was interrupted 1.5 times for an average of approximately 150 minutes.

If one works on these numbers a little bit, and it doesn't take a calculator to do so, one can translate these statistics into an availability of 99.97 percent.

There are probably few electric utility industries around the world that can beat this performance record. Unfortunately, there exists data that also show a slow degradation in system reliability in the same period.

In terms of just the number of interruptions, the utilities surveyed by DOE experienced an average 14.2-percent increase in interruptions over the survey period. More importantly, however, many consumers are finding it difficult to keep up with the spiraling cost of electric energy.

In many instances, because of certain consumers' low valuation of electric energy, providing less expensive but lower reliability electric service may be a viable future option for the industry.

This type of service is already available to many large industrial users who do not value high reliability as much, and therefore, prefer to sacrifice reliability for cost.

The issue of what is an appropriate level of reliability has been addressed by DOE in the National Electric Reliability Study. In addition, the study investigated the various ways investment decisions could be made to achieve cost-effective reliability.

Overall, the study did not answer any of the questions quantitatively. What the study did do, however, was highlight the state-of-the-art and underscore areas of weakness in our ability to address the reliability issue.

Since I participated as a consultant in the study, allow me to elaborate on some of the salient features which I think are important in terms of demonstrating the need for an effective concentrated research program.

Reviewing the definition of reliability as used in industry and government alike, and institutions of higher learning, it becomes very clear that there are various definitions.

For purposes of the National Electric Reliability Study, the definition used was, "The electric power system is considered reliable if it maintains sufficient and properly functioning generating capability and supporting systems to satisfy consumers' needs for electricity."

This definition is very vague, yet it more or less represents what is meant by reliability. At the heart of the definition, in my opinion, is the idea that reliability should be maintained at a level that is consistent with each consumer's perceived valuation of electric service.

This assertion opens up many difficult issues that require an understanding of human behavior and perceptions of the worth of reliability. Attempts have been made to quantify the worth of reliability by equating worth with the costs incurred by consumers due to interruptions.

Unfortunately, the estimates of these costs vary greatly. For example, using the technical contracts associated with the reliability study, the interruption costs for residential customers varies from 3 cents, up to $1.90 per kilowatt-hour.

This large variation suggests to me that we don't know what we are doing. In the commercial and industrial sectors, we see the same sort of variation. For example, in the industrial sector, we see interruption costs ranging from 21 cents to $8.87 per kilowatt-hour.

These numbers quite clearly must be refined, and they can only be refined, in my opinion, after we have developed a sound methodology for calculating the worth of reliability. Equating worth of reliability with interruption cost is one way to do it, but I don't think it is the only way.

In addition, the definition also states that the supporting systems are to be included in the determination of system reliability. An electric supply system is a complex interconnection of supporting systems which we have great difficulty in modeling at this time, and especially when operating constraints are considered.

In general, we need more clarification of what is acceptable system performance and what is not, and we need to define the performance criteria in a way that it can be measured, calculated, and used in assessing the tradeoffs between reliability and cost.

We have come a long way, but the industry of today is very different from the industry of just 10 years ago. Because of financial challenges, it is not even clear what role reliability is playing or should play.

Recent studies at Oak Ridge National Laboratory have shown, for example, that oil-based utilities should discard old generation capacity reliability criteria and aggressively build coal and nuclear plants, even if reserve margins exceed 50 percent.

It is common now for utilities to plan new plant additions to insure adequate capacity all but 0.1 days/year, on average. This level of reliability translates into reserve margins between 15 and 25 percent, depending on the unit availabilities and load characteristics. Studies that suggest that higher reserves, and hence, higher reliability levels are more economic, some argue, are using an incomplete definition of reliability.

As mentioned at the beginning of my testimony, we have the capability to calculate probabilistic reliability indexes for both the generation and distribution system.

However, although distribution level reliability methods are reasonably accurate in an absolute sense—that is, if you make a measurement you can interpret that in terms of a consumer's valuation of service—generation system reliability measures are meaningful only in a relative sense.

Because it is uncommon for utilities to analyze the reliability of the system as a whole due to inadequate probabilistic techniques, it is difficult to interpret the impact of a given level of generation system reliability on the reliability of service even at the feeder level.

Because of this inadequacy, assessing the cost-effectiveness of adding more or less generation capacity in terms of customer level reliability is difficult.

Several utilities have attempted to fill this analysis void by pulling together a variety of tools which were developed for other purposes. Some success has been realized from this effort, and in one instance, a utility is considering adopting the procedure and associated reliability indices for decisionmaking purposes.

This is a step in the right direction. Another characteristic of current reliability methods is that they produce indexes which describe only average performance and have little or no meaning at any given time.

Turning to the bulk system analyses, we find they are performed using deterministic stimulation tools which assess the steady state and dynamic performance of the system when subjected to planner defined contingencies, such as loss of generation or loss of a major line.

These methods do not produce indexes that can be easily related to either generation or distribution system reliability indices.

Further, the contingencies analysed must be defined by the planner which places a tremendous burden on him to select the bounding contingencies. Transmission system probabilistic reliability analysis techniques have not been highly developed because of the complexity of the bulk system, data inadequacies, and perhaps the fact that up to 80 percent of customer interruptions are caused by distribution outages.

Reviewing outage statistics, however, shows that all 12 of the worst interruptions in the period 1974-79 were initiated in the transmission and distribution systems. The worst interruption left almost 3 million people out of service for up to 25 hours.

In summary, we seem to be addressing the reliability issue in a piecemeal fashion, and when I say piecemeal, I mean piecemeal in a theoretical sense—due to inadequate techniques, insufficient data, and perhaps, because of an absence of a clear workable definition of system reliability.

Because of increasing costs, the utility industry has made a concentrated effort to improve operating procedures through the use of modern energy control centers. Although few recorded interruptions flag system operation as a major cause of system problems, I feel that current reporting procedures attribute too many interruptions to miscellaneous events, that is, events other than weather, component outages, and system operation.

If these interruptions are really system operation related, which is difficult to assess, or if we take the attitude that weather and component outage interruptions reflect a failure in system operation, there is much to be gained by assessing the reliability contributions of system operation.

A clear example of this would be the use of lightning locater systems—and this is an example I picked just for the purposes of the testimony. I am not pushing lightning locating systems—in those areas where lightning storms are a major cause of interruptions.

Only two utilities to my knowledge have up-to-date lightning trackers which can pinpoint both location and intensity to within a square mile. These data could be used to shift load off of vulnerable transmission lines for the duration of the storm, thus preventing the electromechanical shocks induced by line tripping which in turn initiates cascading.

This is an example of how we could use up-to-date technologies integrated with operating procedures to avoid some of the cascading failures that we have had.

Given that the worst interruption experience in the period 1974–79 was initiated by thunderstorms, resulting in damage in excess of an estimated $300 million, an investment of $0.1 million seems modest if such catastrophic events can be avoided.

At this time, planners cannot include operating capability in a formal way in their reliability analyses. Although some utilities do incorporate an operator's ability to redispatch generation or to switch lines in their contingency studies, few, if any, attempt to define the associated reliability credits attributable to the operating capability.

Tradeoff analysis where hardware is replaced by data acquisition and control requires analytical tools that do not currently exist. Under DOE-funded research projects, significant progress has been made in unraveling the various operating states of the electric energy system.

This understanding has been invaluable to utilities who have active restoration planning procedures. Such procedures must be implemented immediately after emergency control actions have failed to maintain the integrity of the system.

Typically, the purpose of most restoration procedures is to disconnect the affected area and thereby protect the major equipment needed to restore the system to its normal operating state.

Because the power system is so complex, executing each step at the right time to minimize the extent and duration of the interruption requires extensive data acquisition and control capability.

Although many utilities have restoration procedures, it is felt that, in general, significant reductions in the duration of interruptions stemming from transmission level outages could be realized with the development of advanced restoration methods.

To conclude my testimony, let me point out that some of the weaknesses in current methods are being addressed now by DOE and EPRI. However, in my opinion, we have reached a point where the expansion of our energy supply involves such complex technical, social and behavioral issues that current system analysis methodologies simply are not capable of quantifying the tradeoffs between the various decision paths.

Advanced large-scale systems research which explores new perspectives of the electric supply system is needed if we are indeed interested in answering the questions posed in Mr. S. M. Dean's 1938 statement.

Mrs. **Bouquard**. Thank you very much.

[The prepared statement of Mr. Sullivan follows:]

Testimony on U.S. Electric Power System Reliability Before The House Subcommittees on Energy Development and Application, and Energy Research and Production

by

R. L. Sullivan, Professor
Department of Electrical Engineering
University of Florida
June 8, 1982

I would like to begin my testimony by quoting from a technical paper written by Mr. S. M. Dean[1]:

> "One of the really difficult problems faced by those responsible for planning of electric supply systems is that of deciding how far they are justified in increasing the investment in their properties to improve system reliability. While the problem is not at all new in the industry, it has nevertheless taken on greatly increased significance in the last few years."

In some sense, this quote captures the spirit of much of the discussion being presented in these hearings - yet Mr. Dean's paper appeared in 1938. Some forty-four years later, it is interesting to find that the statement is even more appropriate. In fact, the thrust of the National Electric Reliability Study[2] was directed toward this exact issue. We have made progress in addressing the issue of cost-effective reliability, but the progress has evolved along many fronts. Briefly, the research community and industry have attacked the issue from the perspective of the individual systems that comprise the electric supply. Further, two very different theoretical approaches have been employed. One approach simulates system operation over a given time interval and investigates system performance in the face of a variety of contingencies. The other approach is more analytical and incorporates the random behavior of system components. Significant progress has been made in developing both simulation and analytical tools for planning generation and distribution system expansions, but less progress has been realized in developing transmission system analysis tools that explicitly incorporate system design parameters and operation procedures. Because of the structural and operational complexity of the transmission system, reliability assessments are usually restricted to deterministic simulations of system performance. Although we have refined our simulation capability tremendously over the years, current simulation tools rarely produce an overall index of performance that can be used to assess the cost-effectiveness of the reliability of the system as seen by consumers.

Recent new fronts have developed because of the intense interest in the cost-effective reliability issue in the electric utility industry. In particular, much more emphasis is being placed on advanced system operation than ever before as a means of achieving cost-effective reliability. Security dispatch concepts are being routinely implemented to avoid operationally induced interruptions. Further, recognition that all interruptions cannot be avoided at a reasonable cost has produced keen interest in advanced restoration procedures. Interruptions statistics suggest that uncoordinated restoration procedures can actually aggravate the severity of interruptions. In summary, we have made progress, but we still lack the systems technology to adequately address the concerns expressed in Mr. S. W. Dean's 1938 statement.

How effective have we been in creating a reliable power supply for the Nation using the planning tools developed over the years? The answer to this question based on recent rather incomplete statistics of eight utilities surveyed by DOE indicates that from 1974-1979 each customer was interrupted 1.5 times for an average of approximately 150 minutes. In terms of service availability, this is equivalent to a 99.97% availability. There are probably few electric utility industries around the world that can beat this performance record. Unfortunately, there exists data that also show a slow degradation in system reliability in the same period. In terms of just the number of interruptions, the utilities surveyed by DOE experienced an average 14.2% increase in interruptions over the survey period. More importantly, however, many consumers are finding it difficult to keep up with the spiraling cost of electric energy. In many instances, because of certain consumers' low valuation of electric energy, providing less expensive but lower reliability electric service may be a viable future option for the industry. This type of service is already available to many large industrial users who do not value high reliability as much, and therefore, prefer to sacrifice reliability for cost.

The issue of what is an appropriate level of reliability has been addressed by DOE in the National Electric Reliability Study. In addition, the study investigated the various ways investment decisions could be made to achieve cost-effective reliability. Overall, the study did not answer any of the questions quantitatively. What the study did do, however, was highlight the state-of-the-art and underscore areas of weakness in our ability to address the reliability issue. Since, I participated as a consultant in the study, allow me to elaborate on some of the salient features which I think are important in terms of demonstrating the need for an effective concentrated research program.

Reviewing the definition of reliability as used in industry and government alike, it becomes very clear that there are various definitions.

For purposes of the National Electric Reliability Study the definition used was "The electric power system is considered reliable if it maintains sufficient and properly functioning generating capability and supporting systems to satisfy consumer's needs for electricity." This definition is very vague, yet it more-or-less represents what is meant by reliability. At the heart of the definition, in my opinion, is the idea that reliability should be maintained at a level that is consistent with each consumer's perceived valuation of electric service. This assertion opens up many difficult issues that require an understanding of human behavior and perceptions of the worth of reliability. Attempts have been made to quantify the worth of reliability by equating worth with the costs incurred by consumers due to interruptions. Estimates of these cost for the residential sector range from $.03 - $1.90 /kwh. For the commercial and industrial sectors, they range from $.21 - $8.87 /kwh and $.64 - $8.62 /kwh, respectively[2]. Clearly, we must refine these estimates by first developing a sound methodology which does not appear to exist at this time. Continuing, the definition states that the supporting systems are to be included in the determination of system reliability. An electric supply system is a complex interconnection of supporting systems which we have great difficulty in modeling at this time, and especially when operating constraints are considered. In general, we need more clarification of what is acceptable system performance and what is not, and we need to define the performance criteria in a way that it can be measured, calculated, and used in assessing the trade-offs between reliability and cost. We have come a long way, but the industry of today is very different from the industry of just ten years ago. Because of financial challenges, it is not even clear what role reliability is playing or should play. Recent studies at Oak Ridge National Laboratory, have shown, for example, that oil-based utilities should discard old generation capacity reliability criteria and aggressively build coal and nuclear plants - even if reserve margins exceed fifty percent. It is common now for utilities to plan new plant additons to insure adequate capacity all but .1 days/year, on average. This level of reliability translates into reserve margins between 15 - 25%, depending on the unit availabilities and load characteristics. Studies that suggest that higher reserves, and hence, higher reliability levels are more economic, some argue, are using an incomplete definition of reliability.

As mentioned at the beginning of my testimony, we have the capability to calculate probabilistic reliability indices for both the generation and distribution systems. However, although distribution level reliability methods are reasonably accurate in an absolute sense, generation system reliability measures are meaningful only in a relative sense. Because it is uncommon for utilities to analyze the reliability of the system as a whole due to inadequate probabilistic techniques, it is difficult to interpret the impact of a given level of generation system reliability on the reliability of service even at the feeder level. Because of this inadequacy, assessing the cost-effectiveness of adding more or less generation capacity in terms of customer level reliability is difficult. Several utilities have attempted to fill this analysis void by pulling together a variety of tools which were developed for other purposes. Some success has been realized from this effort, and in one instance, a utility is considering adopting the procedure and associated reliability indices for decision making purposes. This is a step in the right direction. Another characteristic of current reliability methods is that they produce indices which describe only average performance and have little or no meaning at any given time. Turning to bulk system analyses, we find they are performed using deterministic simulation tools which assess the steady-state and dynamic performance of the system when subjected to planner defined contingencies, such as loss of generation or loss of a major line. These methods do not produce indices that can be easily related to either generation or distribution system reliability indices. Further, the contingencies analyzed must be defined by the planner which places a tremendous burden on him to select the bounding contingencies. Recent research results in the area of contingency evaluation are slowly making their way into the industry, thus providing planners with some assistance in identifying the bounding contingencies. Transmission system probabilitistic reliability analysis techniques have not been highly developed because of the complexity of the bulk system, data inadequacies, and perhaps, the fact that up to 80% of customer interruptions are caused by distribution outages. Reviewing outage statistics, however, shows that all twelve of the worst interruptions in the period 1974-1979 were initiated in the transmission and distribution systems. The worst interruption left almost three million people out of service for up to twenty-five hours. In summary, we seem to be addressing the reliability issue in a piecemeal fashion due to inadequate techniques, insufficient data, and perhaps, because of the absence of clear workable definition of system reliability.

Because of increasing costs, the utility industry has made a concentrated effort to improve operating procedures through the use of modern energy control centers. Although, few recorded interruptions flag system operation as a major cause of system problems[2], I feel that current reporting procedures attribute too many interruptions to miscellaneous events i.e., events other than weather, component outages, and system operation. If these interruptions are really system operation related, which is difficult to assess, or if we take the attitude that weather and component outage interruptions reflect a failure in system operation, there is much to be gained by assessing the reliability contributions of system operation. A clear example of this would be the use of lightning locater systems in those areas where lightning storms are a major cause of interruptions. Only two utilities to my knowledge have up to date lightning trackers which can pin-point both location and intensity to within a square mile. These data could be used to shift load off of vulnerable transmission lines for the duration of the storm, thus preventing the electromechanical shocks induced by line tripping which in turn initiates cascading. Interestingly, the forest service uses such systems extensively. Given that the worst interruption experience in the period 1974-1979 was initiated by thunderstorms[2] resulting in damage in excess of an estimated $300 million[3], an investment of $.1 million seems modest if such catastrophic events can be avoided. At this time, planners cannot include operating capability in a formal way in their reliability analyses. Although some utilities do incorporate an operators ability to redispatch generation or to switch lines in their contingency studies, few if any attempt to define the associated reliability credits attributable to the operating capability. Trade-off analysis where hardware is replaced by data acquisition and control requires analytical tools that do not currently exist. Under DOE funded research projects, significant progress has been made in unraveling the various operating states of the electric energy system. This understanding has been invaluable to utilities who have active restoration planning procedures. Such procedures must be implemented immediately after emergency control actions have failed to maintain the integrity of the system. Typically, the purpose of most restoration procedures is to disconnect the affected area and thereby protect the major equipment needed to restore the system to its normal operating state. Because the power system is so complex, executing each step at the right time to minimize the extent and duration of the interruption requires extensive data acquisition and control capability. Although many utilities have restoration procedures, it is felt that, in general, significant reductions in the duration of interruptions stemming from transmission level outages could be realized with the development of advanced restoration methods.

To conclude my testimony, let me point out that some of the weaknesses in current methods are being addressed now by DOE and EPRI. However, in my opinion, we have reached a point where the expansion of our energy supply involves such complex technical, social, and behavioral issues that current system analysis methodologies simply are not capable of quantifying the trade-offs between the various decision paths. Advanced large scale systems research which explores new perspectives of the electric supply system is needed if we are indeed interested in answering the questions posed in Mr. S. M. Dean's 1938 statement.

References

1. "Workshop Proceedings: Power System Reliability - Research Needs and Priorities" EPRI report WS-77-60, October 1978.
2. "The National Electric Reliability Study", DOE Report DOE/EP - 0004 and 0005, April 1981.
3. "Impact Assessment of the 1977 New York City Blackout" DOE Report HCP/T5103-1, July 1978.
4. "Electric Service Reliability: The Customer Perspective" DOE Report ANL/AA-18, September 1978.
5. "Analysis of 12 Electric Power System Outages/Disturbances Impacting the Florida Peninsula" DOE Report DOE/RG/06359-1, December 1980.

Mrs. BOUQUARD. All of the testimony has been excellent.

Mrs. Schneider.

Mrs. SCHNEIDER. I would like to ask Mr. Cagnetta a couple of questions primarily relating to his perception of what the Federal role should be in dealing with utilities. You alluded to it several times, making it quite clear you were looking for signals and direction.

Could you amplify upon that a little, please?

Mr. CAGNETTA. I think that statements were rather broadbased and encompassed a rather long period of time in terms of what has transpired in the sixties and the seventies that have had the dramatic impact on the utility industry. I think it would be difficult to take any specific regulatory impact and isolate that and indicate what could have to be done today to provide a more stable climate.

I think what I was alluding to, in context of the subject, which is enhancing reliability of future generation, as well as existing systems, is that what the utilities need is a stable climate in which to function. What I was trying to point out was the evolution of regulations in a vast array of areas involving environmental issues, involving safety issues, involving the establishment of rate basemaking for utilities, all of which, you know, have had a dramatic impact.

I don't know that I could amplify upon any given one unless you had any specific area you are really interested in.

Mrs. SCHNEIDER. I think, insofar as the Government role is concerned, with your activities, perhaps we could break them down into two general areas. One is the regulatory role of the Federal Government and also budgetary allocations for various energy technologies which, if we are putting our money where our policy goals are, that certainly determines what are our priorities, so it seems to me this administration is very clearly addressing the issue of regulatory reform.

So, let's put that aside a moment. But when it comes to the budget and what direction your utility should take, whether you should make efforts to increase generating capacity, whether you should choose one form of generating capacity over another, I would think that as a businessman from what I have been hearing from business for many years now, is the message:

Get the Federal Government off of our backs, and I would think you would like to have the freedom of choosing the technologies that you would pursue.

Mr. CAGNETTA. Exactly.

Let me state two things relative to our comments. A good example in the regulatory area where utilities are faced with the siting of new fossil plants, specifically coal-fired plants, is the specific agencies or agency that would take the lead role in the licensing of a new coal-fired plant.

I think you will find that, depending upon which utility you talk with, it would be very difficult for them to predict which agency might take the lead in the licensing of a new fossil plant and what a reasonable time frame would be for the licensing of that particular unit to construct it.

It is not uncommon today to speak, even for coal-fired plants, in terms of 3 to 4 years licensing time for a construction permit to be approved for a new facility and this can vary rather dramatically from State to State, as well as the process varying rather dramatically with respect to which agency, Federal or State, would take the lead.

Now, there is a specific area, if we would want to implement a more prudent program for licensing new facilities to speed up construction so that a new unit can come on line in a quicker time frame.

Certainly, the licensing process is one area that should be looked at in terms of streamlining the licensing process. I think EBASCO has testified in the past on these issues and I would be happy to submit additional testimony in this area.

Mr. CAGNETTA. We talk about energy alternatives. I think my testimony clearly indicated in our opinion there is really not an alternative today. The only option open to electric utilities is coal-fired powerplants. With respect to this option, I question their ability to project and plan for, in a reasonable frame, new capacity additions to their system and to be able to project with some reasonable accuracy the cost of these and I would question the statement "reasonable accuracy."

That is unacceptable to the industry which has been used to having alternatives available to them in order to choose between the cost-effective choices.

In that respect, we certainly do need a clear indication of whether or not this country has a nuclear option for future generations of electricity.

Mrs. SCHNEIDER. Before you go any further, does this country have the nuclear option? In other words, you are asking for the Federal Government to give the go-ahead. We are not talking about regulatory reform now, but financial subsidies to the nuclear industry.

Mr. CAGNETTA. Not at all. I don't know that we want financial subsidies at all, and I won't seek that for utilities at this particular point. What we are looking for is the necessary support to remove and eliminate the licensing impediments involved in the safety issues.

Mrs. SCHNEIDER. We have discussed that and put that aside. What else are you looking for, though, for that option?

Mr. CAGNETTA. I think there is an opportunity for the Government, through DOE, to possibly cofund or support, for example, the future standardization of nuclear powerplants for future generation.

I think there is an area where certainly if the safety issues are put aside, there would be an opportunity for Government to support the development of standardization of nuclear plants. Obviously, we have a very skeptical industry at this point in time, who would be hard pressed to commit funds to the standardization effort which has already failed once.

Mrs. SCHNEIDER. Would that also be extended to the standardization of coal-fired plants?

Mr. CAGNETTA. It is unnecessary. In that respect, I think industry has taken dramatic steps. In fact, you heard two individual testimonies from EBASCO and Stone & Webster today that indicated both firms have taken initiatives on their own to develop what they consider reference designs that can be utilized as a standardization approach.

Other companies have done likewise. I don't believe any funding of that type of effort is necessary, because we have already convinced ourselves of the benefits of it and need only to convince utilities who are planning future generations that there are also benefits in a reference approach.

Mrs. SCHNEIDER. Thank you. I have no further questions.

Mrs. BOUQUARD. Mr. Reinschmidt, what is our ability to predict reliability of alternative generating technology?

Mr. REINSCHMIDT. Certainly that ability varies with what alternative strategy we are discussing. Many of these alternative technologies have advanced——

Mrs. BOUQUARD. Take solar, for example.

Mr. REINSCHMIDT. For example, solar, as an illustration, Stone & Webster has participated with the Department of Energy in the development and construction of two demonstration photovoltaic stations, one in Lovington, N. Mex., and one in Beverly, Mass., in order to assess what the problems and reliability of a photovoltaic station are when it is scaled up, not certainly to utility size, but to a practical size, and those have been in operation for approximately 1 year, I believe.

As an example, if I may be permitted an anecdote in that regard, it is certainly widely believed that solar is a very safe form of power. However, it does produce electricity and in translating this to the field, we must install certain safety devices.

That is, one does not want someone's child to climb the fence and to touch this thing while it is in operation, so we have had to install certain safety devices so that if anyone standing on the ground were to touch this equipment, it would turn it off, so to speak, and prevent or hopefully prevent injury or death.

While in the sunny, dry environment of New Mexico, this particular device works very well. In the Northeast, with a somewhat more humid environment, this particular device gave false indications and turned the equipment off unnecessarily.

We have tracked down that particular problem, with that particular piece of equipment and it will be resolved in the future, but these are the kinds of things one does not necessarily anticipate in a laboratory test and one does not necessarily consider all of the safety-related equipment that might be required for a solar photovoltaic station and must be tested out in these programs.

Now, the solar power tower, for example, involves a much more complex technology and it involves the production of steam, the transmission of steam through pipelines, rotating equipment and so on, and that requires much more expensive determinations in development stages than the photovoltaic option.

We would anticipate that in production, a solar photovoltaic station would probably have 98 to 99 percent availability compared to, of course, the inherent limitations of the fuel source, that is, the annual motions and the daily motions of the Sun, the probability of cloud cover, et cetera.

There are certain other factors such as we can always do the maintenance in the nighttime when the plant is not working. However, for other types of technology, windmills which were alluded to by Mr. Fogarty, we would anticipate substantially less availability because of the different technology involved.

So, we have the ability to evaluate analytically, by computer, on paper, what we anticipate this availability to be, either through the natural processes of the motion of the Sun, winds, tides or whatever.

We can evaluate those things in powerplants, but in general they must go to some demonstration plant in order to determine from actual data the availability or the reliability of specific equipment that must be installed.

Mrs. BOUQUARD. Reliability through standardization.

Mr. REINSCHMIDT. Yes. We have undertaken at Stone & Webster, as in EBASCO and other companies, the development of reference fossil and lignite power stations on our own account. While it is not possible to design a completely standard, off-the-shelf plant for reasons given by Mr. Fogarty, such as variations in fuel, variations in cooling water, variations in other site conditions—it is possible to identify or design what we call a reference plant that has certain basic characteristics, and by so doing, we can achieve, hopefully, a number of benefits, one a shortened design cycle.

We have put our reference powerplant design on computer graphics so that when a client comes in the basic reference drawings are there on the computer, and they can be modified for his conditions relatively quickly. Reliability is enhanced because you can provide a better data base, in looking at the reliability of that general type of equipment under that configuration, that type of arrangement, the thermal cycle and so on, and therefore, have a better case for evolving improvements toward improved reliability than if one designs a new custom plant each time.

There are certainly serious questions in getting the industry to accept a reference design in view of the environmental and siting differences and so on, but we feel it will contribute to keeping the costs down, keeping the schedules to a shorter length, and improving the reliability of the resulting plant.

Mrs. **Bouquard**. I believe you said you didn't see any correlation between maintenance hours and forced outage rate?

Mr. **Reinschmidt**. Yes, ma'am.

Mrs. **Bouquard**. How would you go about reducing the forced outage rate?

Mr. **Reinschmidt**. A utility can reduce its forced outage rate by making an intensive study of what is causing its problems. A reliability analysis of the equipment identifying what pieces of equipment are causing the outages for that particular plant or station, and then endeavoring to institute a preventive maintenance program will have substantial long-term benefits on the forced outage rate, although this will require an up-front investment by the utility.

That is, he must maintain or replace equipment before it has failed, which is like replacing light bulbs before they have burned out. It does involve an investment by the utility. It can substantially reduce the forced outage rate.

There are also things utilities can do in outage management in order to reduce the time the unit is out or if a unit must go out for a certain reason, it can perform other items of maintenance during that period it couldn't do while the plant was operating, and therefore, exploit that outage to the maximum extent.

For example, in a nuclear plant where one goes out, not as a forced outage, but a planned outage to refuel, one does all kinds of maintenance and upgrading during that period. Improved outage planning is a factor in trying to reduce the forced outage rate.

Mrs. **Bouquard**. You are saying preplanning maintenance instead of numerically equating your hours?

Mr. **Reinschmidt**. We believe preventive maintenance is certainly one of the major tools in reducing forced outage rates.

Mrs. **Bouquard**. Thank you very much.

Mr. Cagnetta, do you believe the economies of scale still exist for large coal-fired plants?

Mr. **Cagnetta**. I will say, yes, and then qualify it.

The answer is, "Yes," and we obviously participate with utilities in a great deal of system planning studies which I think was discussed at some length by Mr. Sullivan. In these studies, obviously plant sizes and mixes of plant sizes are considered in utility system planning for the future.

While it is difficult to encapsulate the system planning methodologies in simplistic form, in most instances the economy of scales do persist.

Now, in performing these studies you do consider obviously the capital cost and operating cost of the various size systems we are talking about, or plant sizes we are talking about, and we have also attempted to correlate past reliability track records of various sized units which is incorporated into the system planning model.

That probably is one of the more questionable areas of system planning for future generations, because EBASCO is a firm believer that at an appropriate price, larger sized plants can be made as available as smaller sized units.

In fact, I will enhance the earlier testimony that was given, which said that our statistical analyses have shown that 800 megawatt supercritical units operated by many utilities have in fact exceeded the operating availability records of 200- to 400-megawatt units which are entirely different in their design base; namely, subcritical, and should or would expect to be less reliable.

So with respect to unit size, we definitely feel that a larger unit can be more cost effective with all factors considered.

Mrs. Bouquard. How do you view the upgrading of older powerplants as a feasible alternative to new plant construction? What are your feelings in that area?

Mr. Cagnetta. I believe ostensibly a great deal of that is a stopgap measure. Obviously, the hard-pressed financial utilities have to find ways and means to maintain their system reliability and obviously, one of the most cost-effective options which would exist for the short term is to improve and upgrade the operation of existing powerplants.

However, there are limitations. Built into any powerplant is the limited ability to extend its useful life to where even major maintenance might not any longer be cost effective when compared to building larger, more efficient units which would burn cheaper fuels than the existing units.

For this reason, while this is a necessary thing in today's economy, with the problems the utilities are facing, I believe there is a very discrete limit to which the utility can drive this option until such time as the decision has to be made to go with new generation.

Mrs. Bouquard. I toured a Combustion Engineering facility in Chattanooga 2 or 3 weeks ago where we make our boilers. We were commenting on the fact that we are losing our orders for reactor vessels, that we are losing the technology, we are losing our engineers who work on our projects and when we do go back to the nuclear option, when we do go back to increasing our capacity as a country we are going to have old equipment, we aren't going to have the manpower on line to go back and recoup what we started.

What is your feeling on this?

Mr. Cagnetta. I agree with that. As a matter of fact, I guess I was a part, as were many gentlemen here, of the evolution of nuclear energy in the sixties where at that time, the greatest limitation was trained personnel who had had the experience, appropriate experience in the engineering, design, and construction of nuclear facilities.

It took us over a decade to develop that capability on the part of the engineer constructors, on the part of manufacturers and on the part of utilities. At this point in time, with the de facto elimination of nuclear orders, which has existed for some years, we do see the migration of these trained personnel to other areas of technology.

I can relate to this specifically in EBASCO and with many manufacturers we deal with. These people are being recast, if I may use that term, into other areas of work that are no longer nuclear.

If this continues for some period of time—and we expect it at least through the eighties to continue—we will have in effect retrained these people for other energy alternatives such as utilization of their talents in the manufacture, or in the design of coal-fired plants, in which case 10 years henceforth we will be looking for these very same people to be recast once again with the capability to design, engineer and fabricate nuclear components.

Mrs. BOUQUARD. We will probably have to buy the technology from across the ocean?

Mr. CAGNETTA. EBASCO is very active in the foreign nuclear marketplace and we have the opportunity to meet with the members of the various foreign countries who are offering today nuclear steam supply systems as well as total power plant packages to foreign countries who are currently developing the nuclear capability and we have seen clearly demonstrated the capability of these firms to dominate the nuclear industry in the future, including the U.S. nuclear industry, if, in fact, there is to be a nuclear option in the future.

Mrs. BOUQUARD. These certainly aren't happy thoughts we like to consider, but I think it is very timely and I think as we do try to develop an energy policy for our country, which we do not have and have not had—we have talked about it but, at the present time, we do not have a policy, we do not have specific goals coming from DOE—I think we must realize we can't go about this piecemeal.

We are going to have to have long-range plans and dedication and to let the industry know these are our goals, what we want to achieve and what we aren't going to achieve, so that there can be a sense of reliability in the planning and the commitment and for industry as well.

Mr. CAGNETTA. I agree.

Mrs. BOUQUARD. Thank you very much.

Dr. Sullivan, we have enjoyed your testimony very much and we hope you will come back and be with us again. What do you feel about the reliability for customers?

Mr. SULLIVAN. I think it depends on your point of view. It seems to me the industry exists because of the consumer. And to expand the system without consumer input doesn't make too much sense to me.

It is a very difficult problem, however. Often, consumers don't know what level of reliability they could withstand or want. The reason we can't answer these questions is that the reliability has been so good that they have never really had to adjust their lifestyle because of electric service reliability. I think this is a testimony to the fact that the industry is a very solid industry, that it has provided high-quality electric service.

The negative side is that we haven't learned too much about consumer responsiveness to price signals, which is of interest to economists, and we haven't learned too much about consumer's tolerance to different levels of reliability.

I consider these to be research areas, assuming we may wish to design systems in the future which are much more reliability sensitive.

It is a new era, and we have a new set of problems. These problems are not hardware problems, even though a lot of the questions that we have entertained here have been boiler questions and feedwater pump questions, there is another technology, and that is the software and systems technology. I think if we neglect this technology then we are going to miss the boat by misusing the hardware.

Mrs. BOUQUARD. Do you see the need for system engineering studies that would cover certain systems of the network that serve strategic industries such as at an Air Force base, for the purpose of making these systems less vulnerable to establish outage?

Mr. SULLIVAN. The community has talked in recent times about the electromagnetic pulse. There is no doubt about it, current systems are sensitive to electromagnetic signals and high-level EMP could disable the electric energy system.

EMP may be able to disable the electric system. I don't think we know at this point. This subject hasn't been studied in much detail in my opinion. It is not an issue I came here prepared to discuss because I think it is a whole different issue than system reliability, but it is one that perhaps in some circles is important. Protecting our energy system against EMP is a worthy activity.

In terms of more standard reliability analysis, however, I don't see EMP as a major ingredient. I think it is a military issue that is a little bit beyond the issue of power system reliability.

Mrs. BOUQUARD. You don't feel at the moment there is a need for further engineering studies in this area?

Mr. SULLIVAN. If we are talking about power system expansion planning, those things that influence how the electric utility industry expands their current system, I don't think the issue of EMP is considered at all.

It is a relatively new ingredient that is being talked about in very small circles. I don't now of any electric utility system planner that runs his/her expansion plans through an EMP evaluation procedure.

We are not able to evaluate EMP impacts at this point if we wanted to. We are still having problems understanding the performance of the system as it goes through its various States. It has only been in recent time, as a result of DOE research and EPRI research that we have categorized the various States a system can reside in and developed control strategies around these States.

Even this work has not been completed. It was started in 1976 by DOE and EPRI. The funding, as you know, has pretty much curtailed all these programs. The emergency State control program has been cut, and the power system effectiveness program has not been refunded.

All of these programs came out of the Division of Electric Energy Systems, within DOE and out of EPRI to some extent.

There are problems we can't solve now in terms of traditional utility problems, let alone looking at the effect of EMP on system operations.

Mrs. BOUQUARD. Thank you very much.

Thank you gentlemen for your testimony. We certainly appreciate your being with us and sharing with us the benefit of your knowledge. I think we will have further hearings on the 10th at 9:30.

The subcommittee is now adjourned.

[Whereupon, at 11:50 a.m., the subcommittee recessed, to reconvene at 9:30 a.m., Thursday, June 10, 1982.]

U.S. ELECTRIC POWER SYSTEM RELIABILITY

THURSDAY, JUNE 10, 1982

HOUSE OF REPRESENTATIVES, COMMITTEE ON SCIENCE AND TECHNOLOGY, SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS, AND THE SUBCOMMITTEE ON ENERGY RESEARCH AND PRODUCTION,
Washington, D.C.

The subcommittees met, pursuant to notice, at 9:33 a.m., in room 2325, Rayburn House Office Building, Hon. Don Fuqua (chairman of the Committee on Science and Technology and the Subcommittee on Energy Development and Applications) presiding.

Present: Representatives Fuqua, Bouquard, White, Walker, Sensenbrenner, Weber, Gregg, Skeen, and Schneider.

Mr. FUQUA. Today we continue our discussions on the status and outlook for electric power system reliability. We are looking for both informed commentary and a dialog with our witnesses, so that we may all work together to insure the continued quality of service from our electric utilities.

The continued reliability of electric service depends on more than just reliable and efficient equipment. Maintaining reliable systems requires understanding and forecasting a wide variety of external factors. Oil supply disruptions could pose a serious concern for certain utilities. Energy price escalations have not only spurred unprecedented conservation but have led to widespread end-use substitution of electricity for other fuels. High interest rates and reduced demand growth projections have forced cancellation or deferral of many new generating plant additions, implying a continued reliance on existing, aging facilities. As a result, the task of power system planning has become difficult at best, and has required the development and application of sophisticated mathematical methods.

In order to preserve the current level of reliable and cost-effective electric service, we must pursue the development of more efficient technologies and continue to improve those technologies that are now in use.

Research and development has an important role to play in the application of new technologies to improve both equipment and our understanding of the nature of electric power systems.

We welcome today's witnesses, who will assist us in assessing the industry's needs and priorities.

Our first panel will consist of Mr. Walter Brown, president of the North American Electric Reliability Council, and Dr. Marie Corio, senior consultant at the National Economic Research Associates.

Our second panel will consist of Dr. Zack Pate, vice president of operations of the Institute of Nuclear Power Operations; Mr. Kerner Smith, manager of fossil power systems, Babcock & Wilcox Co.; and Dr. A. D. Patton, formerly associated with Texas A&M University and now with Associated Power Analysts.

Without objection, the statement on behalf of Mrs. Bouquard will be placed in the record at this point.

[Material referred to follows:]

MRS. BOUQUARD'S REMARKS FOR ELECTRIC RELIABILITY HEARING, JUNE 10, 1982

This morning as we continue our review of electric power system reliability it would be worthwhile to briefly reflect on testimony from the first day of hearings.

The system that supplies our homes and businesses with electricity requires the coordination of a vast array of components. That we Americans benefit from perhaps the most reliable power system in the world is a tribute to the entire electric utility industry.

There are, however, factors which could negatively affect future electric service reliability. The current situation in the Middle East which becomes more volatile with each passing day, poses a continual threat to a substantial portion of energy supply. And we note that electric utilities in New York and New England depend on oil for one-third to one-half of their fuel.

Our witnesses also expressed a need for stability in Federal Government policy. The boom and bust cycles of research and development prevent long-range planning. Regulatory ratcheting continues to plague the nuclear utilities, and they wait for clear signals on safety, plant standardization and licensing time reduction.

Finally, the financial health of the industry has been at a low ebb for some time.

Each of these problems implies the need for a solution, and we have learned that industry is working in many areas to solve them. We are here then, to affirm our willingness to work with industry to arrive at solutions, realizing the value of reliable electric service to the country's economic health.

Today's testimony is very much appreciated, and will aid our assessment of the needs and priorities of industry.

Thank you, Mr. Chairman.

Mr. FUQUA. At this time, we would be happy to hear from you, Mr. Brown.

Without objection, your prepared statement will be included in the record.

STATEMENT OF WALTER D. BROWN, PRESIDENT, NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Mr. BROWN. Thank you and good morning, Mr. Chairman and ladies and gentlemen.

I am Walter D. Brown; I am president of the North American Electric Reliability Council. Some of you may have heard the previous name that we used—National Electric Reliability Council. We still call it NERC. We are headquartered in Princeton, N.J.

We appreciate the opportunity to respond to your invitation to present testimony before you on the topic, U.S. electric power system reliability. NERC is totally involved in reliability and adequacy of bulk power supply, and I will discuss the council's activities and accomplishments in promoting system reliability. I will also offer some comments on R&D as it relates to reliability.

As president of NERC, I am charged with being a spokesman for the total electric utility industry on matters relating to reliability and adequacy of the electric bulk power supply systems in North America—and I would emphasize "bulk" power. We are dealing only in the generating and transmission part of the business.

It would be naive to suggest that every utility system has an identical conclusion on every detail relating to such matters. On the other hand, there is no greater dedication of effort nor unanimity of conclusion by the executives and engineers of the total industry than in matters which promote reliability and adequacy of the bulk power supply systems in North America.

NERC was created by the utility industry in 1968 specifically to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The council is composed of nine regional reliability councils encompassing virtually all of the electric power systems in the United States and Canada.

I have a map attached to the back of my testimony. I saw no convenient way to display it otherwise.

The creation of NERC by the industry was in response to a recognized need to provide a forum to deal with the reliability of the interconnected networks following the 1965 blackout in the Northeastern United States and Ontario and the blackout in the Pennsylvania-New Jersey-Maryland interconnection in 1967.

Generally, NERC defines reliability and adequacy as separate but interdependent aspects of the bulk power supply system of the electric utility industry. Reliability involves the security of the interconnection transmission network and the avoidance of uncontrolled cascading tripouts that may result in widespread power interruption. Adequacy, on the other hand, refers to having sufficient generating capability to meet the electric demands and the energy required by its customers.

One of the key words which describes the functioning of NERC and its nine regional councils is "coordination"—coordination of planning, such that each council reviews the plans of new facilities proposed by each system to assure that such new facilities are compatible with the interconnected network, especially the review to determine that such facilities will not have an adverse impact on other systems.

Through the operating guides under the cognizance of the NERC Operating Committee, there is a coordination of operations. Furthermore, the NERC forum provides a mechanism for the coordination of planning functions with planning functions with operating functions. All these activities are necessary to promote reliability.

Fundamentally, it is through these activities, plus efforts of various multiregional groups within NERC, that the reliability of the bulk power system is protected and enhanced.

The initial efforts of NERC, after its formation, working with the regional councils, were directed toward resolving the problems which lead to cascading tripouts of transmission lines and widespread blackouts. Various actions were taken; criteria were reviewed and in some cases revised; underfrequency load shedding relays were widely installed; settings were coordinated; changes were made in protective devices; and operating guides were revised.

Through these and other efforts, we firmly believe that the cascading problem is well in hand. Obviously, if reliability or security of the bulk power system is to be maintained, it will require continuous attention, and NERC and its regional councils are resolved to do whatever is necessary to protect the reliability of the system.

It is important to add that NERC, with its access to all the expertise in the industry, is the best organization for this assignment and, in fact, we think the only organization capable of doing it.

Let me now make some comments relating to the adequacy of bulk power supply. NERC has undertaken numerous studies to evaluate both short-term and longer-term adequacy. Starting several years ago, we have issued reports just prior to each peak load season, summer and winter. In fact, just last week a report was released, the 1982 Summer Report, looking at the overall reliability and adequacy. The report's conclusions were rather brief. In part, it said, "* * * bulk power supply in the electric utility systems of North America will be adequate to meet projected summer peak demand and electric energy requirements this year."

The report goes on, "Further, the interconnected transmission networks have sufficient strength and flexibility to avoid widespread cascading interruptions and to deliver power and energy to generation deficient areas should emergencies arise."

It has been our intent and policy to be candid in these assessments. For the United States as a whole, the summer is the peak load season, and the actual peaks cannot be predicted precisely of course, because they are determined in large part by weather conditions, however they occur.

Nevertheless, at the present time there exists adequate reserve generating capacity to accommodate these variations in peak load requirements as well as to deal with operational problems due to equipment malfunctions and disturbances on the transmission network caused by lightning and other weather conditions.

As to the longer-term assessments, NERC has annually, since 1971, made a study of adequacy of bulk power supply looking 10 years or more into the future. With your permission, I would like to submit the following report for the record—the "11th Annual Review." This report is the latest that has been issued. The 12th annual report is presently in the final draft stage and will be released later this summer.

Mr. FUQUA. Without objection, it will be included in the record.

Mr. BROWN. Both the 11th and 12th annual reports conclude that for the short term there is adequate generating capacity installed and operable. Further, it indicates that plans for future additional generating units would provide an adequate capability to meet presently forecasted load requirements. The 12th annual report is in the final draft and is not yet available in published form.

The report, however, expresses serious concern about the future adequacy for much the same reasons as indicated in your charter for these hearings—cancellations and delays in stallation of new units and unforeseen increases in electric power demand.

In addition, the report postulates serious impediments to the completion and operation of new nuclear and coal-fired generating base-load units. It also emphasizes that the financial capability of most systems places a limit on their ability to construct needed new bulk-power facilities.

It would be appropriate to comment here that new generating units are needed not only to meet peak-load requirements but to supply the energy requirements throughout the year.

Perhaps the greatest threat to an adequate bulk-power supply for the future is the long lead time to bring new generating units into service from final planning decisions to commercial operations. The chairman of NERC recently commented that a way must be found to substantially reduce the lead time in installing new facilities—generating and transmission—if we are to have any hope of providing an adequate power supply for the future. In dealing with lead times of 12 or more years, it is humanly impossible to accurately forecast future needs. Materially reduced lead times would ease the impact of the uncertainty of the future and would also lessen the financial burden on the customers as well.

Realistically, the only options we have technically for new generating units available to the industry, of any substantial amount, are nuclear and coal-fired. Other organizations, I am sure, will address the nuclear issue, but let me comment about the coal a little.

There are many potential impediments to the construction of new coal-fired generating units. In addition to the very siting of such units, environmental issues abound, as you know. Most recent is the issue of acid rain, a phenomenon which has been approached with perhaps more emotion than facts.

The industry, on its own and with the assistance of the Electric Power Research Institute—EPRI—has for some time been spending a great deal of money and effort to gather scientific data to determine the formation, transportation, and effects of acid rain. The scientific community is far from agreement on the cause and effect of this phenomenon.

NERC has serious concern for the future adequacy of bulk power supply if various acid rain legislative proposals were to require massive retrofitting of generating plants. Even if the cost of such a requirement were not an issue, it would obviously shift money to that project away from new construction programs. In addition, from a technical standpoint, some amount of generating capacity would be prematurely retired rather than retrofitted and therefore compound the adequacy problem.

The study of the acid rain problem should have a high priority R&D program lest the industry be forced into a program which may not make any noticeable improvement in the problem itself.

The founders of NERC exhibited great foresight when they created this organization by encompassing the nine regional councils. The officers and staff of NERC work through the officers and staffs of the regional councils, which in turn work with the individual systems. Furthermore, the members of the NERC board of trustees and officers of the regional councils are chief executives in most cases or at least high-level executives of their respective systems. This combination provides a most effective administrative arrangement which puts NERC in a position to collect credible data and information necessary to analyze and appraise any situations relating to reliability and adequacy of bulk power supply of the electric utility systems in North America.

We think we have proven to be dynamic and capable of dealing with different problems in a credible manner. Various documents are issued on a regular basis, and specific issues are addressed as they arise. For example, NERC appraised the potential impact on reliability prior to the national coal strikes in 1977 and 1980 and made an after-the-fact analysis after the strikes. NERC appraised the results of the transfer of coal-fired energy to displace oil to document the effectiveness of the industry in saving what we found to be some 300,000 to 400,000 barrels of oil per day through the transfers of energy over the transmission network.

Several years ago, NERC took over the responsibility of the generating availability data system [GADS]. This program is being continually strengthened to provide a credible documentation of the availability records of generating units industry wide. This effort is expected to result in improved availability of generating units as design and operating engineers throughout the industry apply their expertise to remove or minimize the causes of forced outages and unavailability.

Much research is being pursued to improve the performance of the components in a generating plant, the characteristics of fuel, and the combustion process. Any progress which will increase the availability of operating units will be beneficial in the overall economics and reliability of the supply of electricity.

I have attached a list of the various recent NERC reports; I have a few here that are available, for anyone who may be interested. All our reports are distributed widely to industry personnel, Government agencies, and other interested parties.

NERC and the regional councils have worked closely with Department of Energy representatives to keep them abreast of reliability and adequacy. We have been called upon by the Government to serve as a resource to the Emergency Electric Power Administration in the event of a national defense emergency.

To meet the Nation's needs for electric power during such emergencies, certain members of the NERC staff and regional council staffs will be asked to serve as "special Government employees serving without compensation."

NERC also works closely with EPRI to provide data and information as a basis for any of their R&D activities. We also maintain liaison with the three utility trade associations—American Public Power Association, Edison Electric Institute, and the National Rural Electric Cooperative Association.

We are a source of various data, information, analysis, and appraisals for the electric utility industry on reliability and adequacy matters. We have attempted to remain objective and maintain credibility.

In conclusion, let me say that we are dedicated, to the best of our ability, to maintain a reliable and adequate bulk power supply system in North America in spite of the obstacles and uncertainties that exist. We believe that electricity is a fundamental ingredient of the economic health of any industrialized nation and an essential requirement of the health and welfare of citizens. We also believe a reliable and adequate power supply is a necessity for the national security of the Nation.

I find it hard to understand the argument by some who would claim the utility industry is "too reliable." It seems to me that most people find many, if not most, other products and services of poor quality. Surely it is the prudent policy of any nation which has a quality electric system to keep it that way.

I thank you.

[The prepared statement of Mr. Brown, plus "11th Annual Review" report follows:]

Testimony of Walter D. Brown, President
North American Electric Reliability Council
Before the Joint Hearing of
Subcommittees on Energy Development and Applications
and Energy Research and Production
U.S. House Committee on Science and Technology

June 10, 1982

Mr. Chairman, I am Walter D. Brown, President of the North American Electric Reliability Council, usually referred to as NERC, with headquarters in Princeton, New Jersey. We appreciate the opportunity to respond to your invitation to present testimony and appear before this joint hearing of the Subcommittees on Energy Development and Applications and Energy Research and Production on the topic, "U.S. Electric Power System Reliability". NERC is totally involved in reliability and adequacy of bulk power supply, and I will discuss the Council's activities and accomplishments in promoting system reliability. I will also offer some comments on R&D as it relates to reliability.

As President of NERC, I am charged with being a spokesman for the total electric utility industry on matters relating to the reliability and adequacy of the electric bulk power supply systems in North America. It would be naive to suggest that every utility system has an identical conclusion on every detail relating to such matters. On the other hand, there is no greater dedication of effort nor unanimity of conclusions by the executives and engineers of the total electric utility industry than in matters which promote the reliability and adequacy of the bulk power supply systems in North America.

NERC was created by the electric utility industry in 1968 specifically to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The Council is composed of nine regional reliability councils encompassing virtually all of the electric power systems in the United States and Canada (see attached map).

The creation of NERC by the industry was in response to a recognized need to provide a forum to deal with the reliability of the interconnected networks, following the 1965 blackout in the Northeastern United States and Ontario, Canada, and the blackout in the Pennsylvania-New Jersey-Maryland Interconnection in 1967.

Generally, NERC defines reliability and adequacy as separate but interdependent aspects of the bulk power supply system of the electric utility industry in North America. RELIABILITY involves the security of the interconnected transmission network and the avoidance of uncontrolled cascading tripouts that may result in widespread power interruptions. ADEQUACY refers to having sufficient generating capability to meet the electric demands of all customers.

One of the key words which describes the functioning of NERC and its nine regional councils is "Coordination": coordination of planning such that each council reviews the plans of new facilities proposed by each system to assure that such new facilities are compatible with the interconnected network. Especially the review is to determine that such facilities will not have an adverse impact on other systems. Through the Operating Guides under the cognizance of the NERC Operating Committee there is coordination of operations. Furthermore, the NERC forum provides a mechanism for the coordination of planning functions with operating functions. All of these activities are necessary to promote reliability.

Fundamentally, it is through these activities -- plus efforts of various multiregional groups within NERC -- that the reliability of the bulk power system is protected and enhanced.

Initial efforts of NERC, after its formation, working with the regional councils, were directed toward resolving the problems which lead to cascading tripouts of transmission lines and widespread blackouts. Various actions were taken: criteria were reviewed and, in some cases, revised, underfrequency load shedding relays were widely installed and their settings coordinated, changes were made in protective devices, and operating guides were revised.

Through these and other efforts, we firmly believe that the cascading problem is well in hand. Obviously, if reliability or security of the bulk power system is to be maintained, it will require continuous attention - - and NERC and its regional councils are resolved to do whatever is necessary to protect the reliability of the systems. It is important to add that NERC, with its access to all the expertise in the industry, is the best organization for this assignment - - and in fact the only organization capable of doing it.

Let me now make some comments relating to the "Adequacy" of bulk power supply. NERC has undertaken numerous studies to evaluate both short term and longer term adequacy. Starting several years ago, we have issued reports just prior to each peak load season, summer and winter. In fact, just last week a report was released: "1982 Summer Assessment of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America". The report's conclusions were rather brief. In part it said: ". . . bulk power supply in the electric utility systems of North America will be adequate to meet projected summer peak demand and electric energy requirements. Further, the interconnected transmission networks have sufficient strength and flexibility to avoid widespread cascading interruptions and to deliver power and energy to generation deficient areas should emergencies arise."

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As to longer term assessments, NERC has annually, since 1971, made a study of adequacy of bulk power supply looking ten years or more into the future. With your permission I would like to submit the following report for the record: "11th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems." This report is the latest of such reports. The 12th Annual report is presently in the final draft stage and will be released later this summer.

Both the 11th and 12th Annual reports conclude that for the short term there is adequate generating capacity installed and operable. Further, it indicates that plans for future additional generating units would provide an adequate capability to meet presently forecasted load requirements. The report, however, expresses serious concern about future adequacy for much the same reasons indicated in the Charter for these hearings: cancellations and delays in installation of new generating units and unforeseen increases in electric power demand. In addition, the report postulates serious impediments to the completion and operation of new nuclear and coal-fired generating base load units. It also emphasizes that the financial capability of most systems places a limit on their ability to construct needed new bulk power facilities. It would be appropriate to comment here that new generating units are needed not only to meet peak load requirements but to supply energy requirements throughout the year.

Perhaps the greatest threat to an adequate bulk power supply for the future is the long lead time to bring new generating units into service from final planning decisions to commercial operations. The Chairman of NERC commented recently that a way must be found to substantially reduce the lead time in installing new generating and transmission facilities if we are to have any hope of providing an adequate power supply for the future. With lead times of as long as 12 or more years, it is humanly impossible to accurately forecast future needs. Materially reduced lead times would ease the impact of the uncertainty of the future and also lessen the financial burden on customers as well.

Realistically, the only options for new generating units available to the utility industry are nuclear and coal-fired units. Other organizations will no doubt address issues involving nuclear units. There are many potential impediments to the construction of new coal-fired generating units. In addition to the very siting of such units, environmental issues abound. Most recent is the issue of acid rain, a phenomena which has been approached with perhaps more emotion than with facts. The industry, on its own and with the assistance of the Electric Power Research Institute (EPRI), has for some time been spending a great deal of money and effort to gather scientific data to determine the formation, transportation, and effects of acid rain. The scientific community is far from agreement on the cause and effect of this phenomena.

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In conclusion, we are dedicated, to the best of our ability, to maintain a reliable and adequate bulk power supply system in North America in spite of obstacles and the uncertainties that exist. We believe that electricity is a fundamental ingredient of the economic health of any industrialized nation and an essential requirement of the health and welfare of citizens. We believe a reliable and adequate power supply is a necessity for the national security of a nation.

I find it hard to understand the argument by some who would claim the utility industry is "too reliable". It seems to me that most people find many, if not most, other products and services of poor quality. Surely, it is the prudent policy of any nation which has a quality electric power supply system to assure its continuance.

LISTING OF RECENT NERC REPORTS

Review of Overall Reliability and Adequacy of the North American Bulk Power Systems:
- 10th Annual Review (August 1980)
- 11th Annual Review (August 1981)

Data Summaries of Projected Peak Demand, Generating Capability, and Fossil Fuel Requirements for the Regional Reliability Councils of NERC:
- 1980 Summary (July 1980)
- Electric Power Supply and Demand 1981-1990 (July 1981)

Assessments of the Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America:
- 1980/81 Winter Assessment (November 1980)
- 1981 Summer Assessment (May 1981)
- 1981/82 Winter Assessment (November 1981)
- 1982 Summer Assessment (May 1982)

Operations Review of the Overall Reliability and Adequacy of the Bulk Power Supply in the Electric Utility Systems of North America - Summer 1980

Oil Conservation Through Transfers of Electric Energy in the Electric Utility Systems of North America (February 1980)

Transfer Capability - A Reference Document (October 1980)

Review of Major Power Systems Interruptions in the North American Bulk Power Systems Between July 1, 1976 and December 31, 1978 (August 1979)

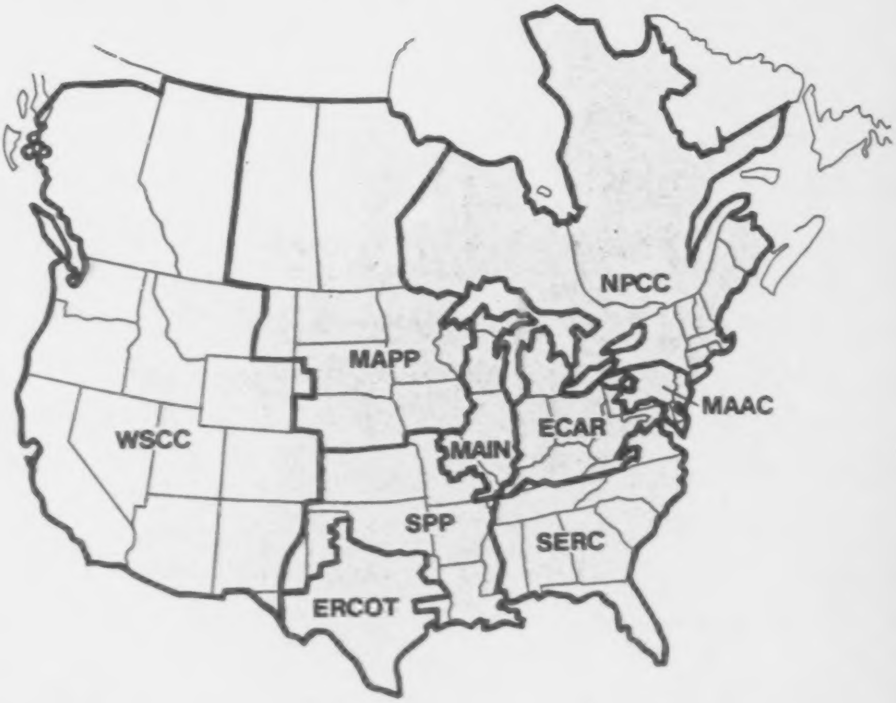
Generating Availability Data System Reports:
- Ten Year Review 1971-1980
  Report on Equipment Availability

- Ten Year Review 1971-1980
  Component Cause Code Report

- 1980 Quarterly Reports on Nuclear and
  Medium and Large Fossil Steam Units

- 1981 Quarterly Fact Sheets on Nuclear and
  Medium and Large Fossil Steam Units

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL



ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interpool Network
MAPP	Mid-Continent Area Power Pool
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the RELIABILITY and ADEQUACY of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils encompassing virtually all of the power systems in the United States and Canada.

RELIABILITY and ADEQUACY are separate but interdependent aspects of the bulk power supply system of the electric utility industry in North America. RELIABILITY involves the security of the interconnected transmission network and the avoidance of uncontrolled cascading tripouts that may result in widespread power interruptions. ADEQUACY refers to having sufficient generating capability to meet the electric demands of all customers.

BIOGRAPHY

Mr. Walter D. Brown is a graduate of the University of Pittsburgh, Pittsburgh, Pennsylvania, with a B.S. in Electrical Engineering (1938) and a M.S. in Business and Engineering (1948). Essentially his whole career has been related to the electric utility industry. After graduation from college, he was employed by Duquesne Light Company, Pittsburgh, Pennsylvania in various operating assignments, becoming Assistant General Superintendent of System Operations and Communications from 1950-1958. For the next five years, he was Manager of Electric Utility Engineering for Middle West Service Company, Chicago, Illinois, followed by five years as System Engineering Editor of Electrical World, McGraw-Hill's weekly magazine for the electric utility industry. In 1970, when the North American Electric Reliability Council (NERC) established a staff, he was hired as Administrative Manager. In 1977, he was Executive Vice President of NERC, and in 1980, was selected as President of NERC, his present position.

Mr. **Fuqua**. Thank you, Mr. Brown.

Now we will hear from Dr. Corio.

Without objection, your prepared statement will be included in the record.

STATEMENT OF DR. MARIE CORIO, NATIONAL ECONOMIC RESEARCH ASSOCIATES ACCOMPANIED BY ROBERT G. UHLER, VICE PRESIDENT, NATIONAL ECONOMIC RESEARCH ASSOCIATES

Dr. **Corio**. Good morning, Mr. Chairman, ladies, and gentlemen.

Before I begin my talk, I would like to make just a few introductory comments. I have here Mr. Robert Uhler, who is a vice president at NERA. His role here is, to the extent that we get into some broad policy issues—he has considerable experience and expertise in this area.

Second, I will be basing my comments today on an article I published recently in the "Public Utilities Fortnightly." In addition, I would like to introduce into the record two more complete reports on the study that I presented in that article.

Mr. **Fuqua**. We will make them a part of the hearing file.

Dr. **Corio**. Thank you.

As you know, based on my testimony, my research has focused on the generation of large coal-fired units. The reason that this topic has been of interest to utility regulators and utility executives at large, and should be of interest to this committee, is that in an era where we are relying more and more on coal generation to produce electricity, we are finding that the generating units which are available to produce these kilowatt hours are becoming less and less reliable.

Let me tell you why we are relying on them more and more in the future. First of all, we are entering a period where there is very little new construction being planned by utilities. To the extent that they are planning new construction, they are planning less and less of that to be nuclear. Consequently, we are facing a situation where we are looking more and more toward coal to be our baseload fuel.

What that means is, to the extent that we have a coal unit that is unavailable and we have to replace that with a more expensive fuel, such as oil, we are first of all relying more and more on foreign oil to produce electricity, and, second of all, we are actually increasing the costs to the consumer, because we are replacing a relatively inexpensive fuel—that is, coal—with something that is much more expensive—namely, oil.

Now let me turn to the research that I have done at NERA. Basically, what I did is look at the performance of large coal-fired generating units. What I did is try to explain the performance of these units in terms of a number of factors. I tried to explain it in terms of the engineering characteristics of these units, in terms of the quality of coal being burned in the units, in terms of some very general characteristics, and some financial variables.

The performance measures that I looked at were two: Equivalent availability and heat rate. Equivalent availability is the percent of time that the unit is available to run at full capability—basically, the percent of the time during a year that it is available to run. Heat rate is the amount of fuel that is needed to produce a kilowatt-hour of electricity.

We did an econometric model, a statistical analysis—whatever phrase means the most to you. I do not want to get too technical in terms of the actual statistics that we used. But let me summarize some of the results that we found.

In my testimony I discuss the results of these models at great length, but I would like to talk about basically two sets of results that I found very interesting.

First of all, there were what I call my corroborative results, corroborative in the sense that they corroborate quantitatively what engineers have known qualitatively. For example, I found that supercritical units had lower equivalent availabilities than subcritical units by roughly 6 percentage points. This was hardly a surprising result to engineers, but the 6 percentage points was something new, something they had not had a handle on before.

I found that units with balanced draft boilers perform better than positive pressure boilers by roughly 5 percentage points. Again, the number means something, not so much the result.

Finally, units with cyclone furnaces had lower equivalent availabilities than those without by roughly 4.5 percentage points.

The second set of results I would like to talk about is what I call the surprising results, surprising in the sense that when I talked to engineers and people in the industry, they were somewhat surprised by the results.

For example, I mentioned to you that balanced draft boilers perform better than positive pressure boilers. Consequently, what we saw in the early 1970's was a conversion by utilities of units with positive pressure boilers to balanced draft. What we found in our results is that, after they converted to balanced draft, they performed no better than they had before, which was somewhat surprising.

The second thing I found out was, again, when I first started working in this area, I had read a lot of reports and studies, and everybody talked about the ash content of the coal—namely, the higher the ash content of the coal, the worse your unit was going to perform. So I expected when I put this variable into my analysis that I would find that it had a significant impact on availability. It did not. As a matter of fact, it had no apparent effect on availability.

After doing a bit of research, what we concluded was that this is probably not the best measure of the ash characteristic in the coal. Indeed, what engineers and plant managers are worried about is something called "slagging potential" of the coal. That means the ash forms a lava type of substance and then sticks to the boiler walls and turning into a hard surface.

The more proper variable would have been ash fusion temperature to include in the model, and unfortunately there are no data around on this variable.

Finally, the sulfur content of the coal: When I talked to engineers and to plant managers, again they told me that sulfur was a good thing to have in the coal because it made the environmental equipment work better. When I introduced that variable into my model, I found that instead of performance improving with the higher sulfur content, it actually deteriorated. Again, a little bit of investigation revealed that possibly things like sulfuric acid, which would form from the sulfur in the coal and corrode a lot of the equipment, could be a reason for my results.

Well, where does that leave us? We included a lot of engineering characteristics, we included variables on coal quality; but what we found was this: that even introducing all these variables, we still had a very strong decline in performance for generating units, and the way we were picking up that decline was in something called the age of the unit.

We found that, even after taking all these variables into account, just solely due to age, a unit would deteriorate in terms of equivalent availability at about 1.5 percentage points a year. That means that in 10 years this unit would have lost 15 percent of its available time just solely due to age.

Again, when we talked to people in the industry, they said, "That's not true; with a certain amount of upgrading and maintenance, you could forestall that kind of deterioration."

Consequently, as economists, we looked toward another explanation for what could be causing this decline, and it happened that the period that we were looking at in our model was the period in which utility financial conditions were eroding—namely, the 1970's.

What we found is that, when we looked at things like the earned rate of return for the utility industry, they were far below what utilities needed to maintain their units and to also maintain an effective position in the financial markets.

When we introduced this factor into our model, we found that, consistently, the earned rate of return affected the performance of coal-fired generating units and, furthermore, once we introduced this variable, the so-called age effect that we had was reduced significantly to roughly half of what it had been before. As economists, we found this result particularly pleasing, and certainly it made sense to people that we talked to in the industry.

That is a very brief capsulization of what we did in terms of the analysis at NERA, and in summary I would like to just make four points.

First of all, as I said, the performance of coal-fired generating units has declined over the past decade.

Second, while engineering characteristics and coal quality explain differences in performance across generating units, they do not explain why the performance of all units has declined over time.

We offer two explanations for the decline in performance over time: First, age; and, second, the utilities' financial condition. Of the two explanations, we found that the latter—that is, the financial condition of the utilities—explains that decline better.

Finally, the point I would like to make is really a caveat. We feel that the analysis we have done is a major step in terms of analyzing performance in that it provides a framework for looking at possible factors affecting generating unit performance. But like all research, it can always be further refined and updated, and so in order to use the tool that we have provided the industry with effectively, it should continue to be updated and refined in order for people to make informed decisions based on the results.

That concludes my testimony. Thank you.

[The prepared statement, plus additional reports of Dr. Corio follow:]

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NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
NEW YORK / WASHINGTON / PHILADELPHIA / LOS ANGELES / PALM BEACH / ITHACA

TESTIMONY
of
MARIE R. CORIO

before the
U.S. House of Representatives
Subcommittee on Energy Development
and Applications
and
Subcommittee on Energy Research
and Production
of the
Committee on Science and Technology

Washington, D.C.
June 10, 1982

BIOGRAPHY OF MARIE R. CORIO

Marie R. Corio is a Senior Consultant with National Economic Research Associates, Inc. She directs research projects of energy issues that require the use of econometric modelling, economic forecasting and statistics. Her work at NERA has concentrated on microeconomic analysis. For example, she has made studies of the long-term elasticities of demand for electricity, and has prepared local and regional forecasts based on those studies. She has presented testimony before regulatory agencies based on such forecasts.

With two other researchers, Dr. Corio has analyzed the effects of rate structure changes on electricity demand. The results of this research will appear in a forthcoming Electric Power Research Institute publication.

Recently, her research has focused on the performance of coal-fired electric generating units. She has testified on this subject before the North Carolina Utilities Commission. This research will continue with support by EPRI.

Dr. Corio received her Ph.D. degree in Economics, specializing in econometrics and quantitative analysis, from New York University, where she also completed her B.A. in Economics.

June 4, 1982

TESTIMONY
of
MARIE R. CORIO

THE PERFORMANCE OF COAL-FIRED GENERATING UNITS

I. INTRODUCTION

I appreciate this opportunity to testify today as you examine three important issues: (1) the reliability of the U.S. electric power system and the major factors which affect reliability; (2) the relationships between power system reliability and various operational and structural features of the industry; and, (3) the role and paths of future research & development. I must emphasize, however, that my testimony is limited to a summary of my research on the performance over the past decade of large coal-fired generating units. While the insights from this research are informative, my findings are limited by the data and information that were available at the time of the study and should be considered in that context. Because of the limitations, I would strongly recommend continued research on generating unit performance--particularly the inclusion and analysis of additional fuel, equipment and cost data--so that informed decisions based on complete and up-to-date data can be made.

In these days of exorbitant fuel prices and prohibitive construction costs, utility managers and regulatory commissioners throughout the country are turning their attention to the operation of existing generating plants. The questions they are asking are: (1) to what extent can performance improvements offset high fuel prices and forestall the need for new costly capacity, and (2) if commissions adopt incentive programs, what is a reasonable conceptual basis for determining performance standards and what are appropriate numerical standards?

At the same time, the electric utility industry is faced with declining performance of its large baseload coal units. Using two traditional measures of generating unit performance, namely, annual equivalent availability[1] and annual heat rate,[2] we traced the performance over the period 1970-1977 (the latest year for which we had unit data) of a sample of coal units built prior to 1970. We found that, for this sample, equivalent availability dropped an average 1.5 percentage points per year between 1970 and 1977, from 76 percent in 1969 to 64 percent in 1977. (See Figure 1.) For these same units, heat rates were rising by some 75 Btus per year from 9,070 to 9,600. (See Figure 2.) So, not only were these units becoming less and less available, but when they were available they were requiring more and more fuel to generate each kilowatt-hour.

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[1] Roughly defined, equivalent availability is the percent of time over a year that a generating unit is available to run. For a strict definition, see National Electric Reliability Council, Generating Availability Data System, Ten-Year Review, 1970-1979, Report on Equipment Availability, 1980, pp. 83-85.

[2] Heat rate is the amount of fuel (Btus) needed to produce one kilowatt-hour of electricity. There is a distinction between net and gross heat rates. Net heat rates are calculated as the ratio of total Btu's of input fuel to kilowatt-hours of electricity sent out, i.e., excluding electricity used by the generating unit or plant. Gross heat rates include electricity used inhouse in the denominator.

The performance losses from decreased unit efficiency can be significant. For example, in places where losses in coal-fired generation are replaced by oil-fired generation (elsewhere on the system) every 1 percentage point decline in equivalent availability for a single 500 megawatt unit costs ratepayers over $1 million dollars per year. For our entire sample of 80,000 megawatts, the decline between 1970 and 1977 in availability is also equivalent to 20 new 500 megawatt units. At current construction costs, the industry would have to raise $8 billion to replace these efficiency losses. Put simply, the utility industry—already desperately strapped for construction funds—is forging ahead building new plants, while a significant portion of its existing base-load coal capacity is sitting idle or running poorly. Inefficiency is costing both the consumers and the stockholders money.

II. TRADITIONAL METHODS OF MEASURING PERFORMANCE

At present there are two ways of evaluating the performance of generating units. The first way is the engineering study. An expert examines unit outages, pinpoints their causes and, given the built-in design features of the unit, determines which outages could have been avoided and what performance (i.e., equivalent availability and heat rate) could have been realized had the outages been avoided. In short, the level of performance a unit can attain is based on comparing the unit with itself. This makes sense. The engineering study considers an attainable level of unit performance and explains reasons for not attaining that level. However, the attainable level of performance is not an acceptable standard because it is based on an idealized set of operating conditions, that is, when all the equipment in the unit is operating perfectly. A standard is something that can either be met, fallen short of or exceeded. In general, perfect performance can only be met or fallen short of.

The second way of evaluating performance, the comparison group study, takes the opposite route. The expert compares one unit with other units. Instead of looking at "what if" he looks at "what is." Here, the standard is the average performance of units which are roughly comparable in design. This method has certain weaknesses. In most of these studies, only a few general criteria are used to assign a particular unit to a comparison group. For example, the most commonly used industry averages of performance, the EEI/NERC averages,[3] assign units to a group by size and distinguish fuel type only between fossil and nonfossil. Units performing below the average are assumed to be "inefficient" when there may be several factors not explicitly considered which affect availability and could explain poor performance.

Because the EEI/NERC averages are so routinely used as performance standards, it is worthwhile to take a moment to underscore the averages' weaknesses as standards. First of all, these industry performance averages are calculated from groups of units which lump together coal-, oil- and gas-fired generating units. This obscures the fact that coal units have historically shown lower equivalent availabilities than oil units, and oil units lower than gas ones. (See Table 1.) Second, the averages are calculated from groups which lump old and new units together. This camouflages the effect of aging which occurs in these units, as shown in Figures 1 and 2. Third, the averages are calculated for groups based on the performance of several units over ten years. This smooths the wide swings in annual unit performance.

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[3] The Edison Electric Institute/North American Electric Reliability Council averages reflect 10 years of operation.

One attempt to overcome these weaknesses is the sister group study, an offshoot of the comparison group study. The sister group study considers additional distinguishing variables such as fossil fuel type, vintage, and age as the basis for making up groups of units. Unfortunately, as more and more characteristics are considered, the group of generating units becomes smaller. In one study by a regulatory commission, using three additional variables reduced the sister group sample to just six generating units. Statistically, any performance standard based on such small sample sizes runs the risk of having the group's averages being greatly affected by a single unit's performance.

Where does this leave us? Standards derived from any of the methods discussed above are inadequate and can be misused. We believe there is an alternative. Using relatively straightforward statistical techniques, NERA has developed a way of combining the strengths of the engineering study with the insights of the comparison group study while avoiding those studies' weaknesses.

III. THE NERA METHOD OF EVALUATING PERFORMANCE[4]

NERA developed two econometric models of generating unit performance: one to explain annual unit equivalent availability and one to explain annual unit heat rate. Variables used to explain unit performance included engineering design, age, size, vintage, fuel quality, and financial characteristics, age, size and vintage. The two models were based on data from a sample of large coal units. The sample was limited to units larger than 200 megawatts, and built between 1960 and 1974. There were 171 such units, and these were operated by 57 different utilities.

For the first model, historical data on equivalent availability of the units for the period 1969-1977 were derived from two EEI/NERC data tapes.

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[4] A complete technical report as well as testimonies filed before the North Carolina Utilities Commission are available from National Economic Research Associates, Inc., Five World Trade Center, New York, NY 10048

Incidently, a comparison of the tapes, one of which is merely an updated version of the other, indicated great inconsistencies in the data. Therefore, before using the data, we resolved the inconsistencies, in many cases with the help of utility plant managers.

For the second model, historical data on net heat rate of the 171 units were not publicly available.[5] But, we were able to compute gross annual unit heat rates for the period 1969-1977, using a variety of published data sources.

Once we had data for the two performance measures that we were trying to explain, we consulted various published performance studies and talked with numerous engineers around the country to determine which characteristics heavily affect generating unit performance. Our inquiry in this area indicated that certain built-in engineering features and the quality of coal were two important factors in explaining equivalent availability and heat rate.[6] The list of other relevant factors was longer than the list of factors for which data were obtainable. For coal characteristics, we were able to obtain data on heat, sulfur, ash and moisture content. Data on other coal characteristics, such as ash softening temperature, viscosity and grindability, which are important in explaining performance, could not be obtained. For the built-in engineering features, we were able to obtain data on boiler design, boiler manufacturer and turbine-generator manufacturer.[7] Data on design characteristics such as heat release rate were difficult to acquire.[8]

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[5] Unit-specific net heat rate data are not systematically available. Net heat rate data are reported only for units which are the best performers on a system, i.e., the best generating units for which over 50 percent of their capacity was used over the year, on the FPC/FERC Form 1.

[6] The specific factors relevant in explaining performance varied, depending upon which measure was being modeled.

The results from the model of equivalent availability suggest that the factors we were able to include in the model do indeed affect this performance measure. For example, coal quality had several effects on equivalent availability: the higher the sulfur content of the coal, the lower unit equivalent availability; the same is true of the moisture content. The model results also suggest that a unit fueled by coal which is 1 percent higher in both moisture and sulfur content (other things being equal) would have an availability roughly 4 percentage points lower than it would if it were burning higher quality coal. The lower the heat (Btu) content of the coal, the lower the availability. The only coal characteristic which does not appear to affect equivalent availability is ash content. However, this is not a surprising result since the ash softening temperature (a variable for which we do not have data) is considered more important in affecting unit availability.

The results of the first model also suggest that built-in design characteristics have a systematic effect on availability. For example, units with balanced draft boilers have equivalent availabilities some 5 percentage points better than those with positive pressure. Dry ash boilers are 4 percentage points better than cyclone and recirculating boilers are 6 percentage points better than once-through boilers. Generating units with boilers manufactured by Babcock & Wilcox showed slightly higher availability. Also units with GE turbine generators showed higher availability: this could be due to differences in the design of the turbine and generator but the data necessary to make that determination were unavailable at the time of the study. So, a balanced draft, recirculating boiler with a GE turbine-generator could perform 13 percentage points better than a unit without these design and manufacturing characteristics. However, as noted above, the analysis does not take the cost of the equipment explicitly into consideration.

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[7] We were not able to obtain data on the relative costs of different kinds of boilers and different manufacturers' equipment on a systematic basis.

[8] Other variables of interest include preventive maintenance expenses and additional capital expenditures for the generating unit. Unfortunately, data were not available.

To illustrate the effect that changing some factors may have on equivalent availability, consider the following example. Suppose we have a 600 megawatt unit that was built in 1970 which is "now" four years old. It has a balanced draft, recirculating boiler manufactured by Babcock & Wilcox and a Westinghouse turbine-generator. Currently, the unit is burning coal with a heat content of 12,000 Btus per pound, 3 percent sulfur, 10 percent ash and 8 percent moisture. The expected equivalent availability of that generating unit would be 76 percent. Now suppose that the unit had been built with a positive pressure rather than a balanced draft boiler. The expected availability of such a unit would be 71 percent. Suppose, in addition, that the unit had a once-through rather than a recirculating boiler; expected availability would be still lower, 65 percent. Similar calculations could be made for the other explanatory factors.

The second model--the heat rate model--produces similar results with respect to engineering features and coal quality factors. For example, the heat rate model suggests that supercritical generating units have better (i.e., lower) heat rates than subcritical units. Lower levels of ash and moisture in coal improve the heat rate.

What was surprising in both models was that after incorporating many engineering and coal quality characteristics, there was still a strong decline in performance over time. The effect of this declining trend was seen in the strong effect of unit "age" in both models. Neither the engineering factors nor the coal quality factors eliminated the effect of age. These factors explain differences in performance among the various units, but do not explain why the performance of all units has declined over time.

IV. THE DECLINING TREND OF PERFORMANCE OVER TIME

Why is the performance of electric generating units declining? We tried two explanations for the decline in equivalent availability over time.[9] First, as discussed above, we hypothesized that the decline in unit equivalent availability is made up of two components: the age of the unit and the vintage of the unit, defined as the year in which it was built. Were units built in 1967 systematically better or worse than those constructed in 1969? Keep in mind that the vintage of each unit remains the same over time whereas the age increases with each passing year. Our analysis showed that the earlier built units performed better, given their age, than the units built later on (in technical jargon, vintage had a strongly negative coefficient). Age, as might be expected, also adversely affected performance over time. So while new units may perform better than old units, they do not perform better than the old ones did when they were first built.

If age is the true explanation for the decline in performance over time, various interpretations of the aging effect could be offered. One rather pessimistic theory would be that things just naturally get worse and worse. Another theory would be that the utility industry, as a whole, has bought less and less reliable equipment over the years and whose performance has worsened over time.

However, it would be hard to find an engineer who believes that a decline as large as 1.5 percentage points a year is an inevitable effect of aging. The engineers we consulted agree with most of the results of the model. But they did not accept the size of the downward time trend as an inevitable effect of aging. With sufficient maintenance, they explained, a generating plant should be able to perform with minimum deterioration over the years. And yet, all of the units have deteriorated.

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[9] We did a similar analysis for heat rates.

If utilities are buying less reliable plants and then letting the generating units deteriorate, it is easy to guess that an economist would turn to financial explanations. This is what we tried next.

Throughout most of the 1970s, the earned rate of return on equity of utilities declined slightly. At the same time, required returns rose.[10] Thus, the industry's earnings were eroded as the difference between required and earned returns widened. Because data were unavailable for required returns on equity, we could not use the difference between earned and required returns as the financial explanatory variable. Instead we adjusted earned returns by the utility bond rate. The movement in the bond rate is generally assumed to track that of required returns.

NERA computed an adjusted rate of return on equity by subtracting the bond yield from the earned rate of return on equity for the utilities in the sample. These data are shown in Figure 3. Now, because adjusted returns showed a time trend, these data should help explain a time trend in the EEI/NERC unit availability data. The fact that a trended variable correlated strongly with the declining trend in equivalent availability did not surprise us. We, therefore, used a stronger test to determine if the earned rate of return was a significant factor in explaining unit equivalent availability apart from its ability to explain the strong time trend.

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[10] Allowed rates of return also rose. "Required" returns are those requested by the utility; "allowed" returns are those allowed by the commission; "earned" returns are those actually earned by the utility.

We calculated the moving average of the differences between the earned return for each utility in our sample, and the bond yields for the three previous years. The idea here was that in any given year (i.e., removing the time trend completely), the availability of units would reflect the earned net return on equity of the operating utility in the three previous years.

The results were very strong. In every year from 1970 to 1977, the availability of generating units was affected by the previous three years' (adjusted) return on equity. The higher the returns, the higher the subsequent availability. In every year, looking across all coal units in the United States, unit performance was correlated with the previous years' returns of the operating utility. The effect was strongest after 1974, the year in which the required net returns on equity jumped because of increased risks. In contrast, the effect of the age of a unit was barely significant, dropping to a decline of 0.8 percentage points per year. Moreover, the effect of vintage also decreased. However, the impact of the engineering factors remained the same.

There was the possibility that we had a chicken and egg situation. If plants perform poorly (i.e., low availability), a utility has to spend more money on purchased power, and more dollars should be devoted to maintenance. If these things happen, the utility's rate of return would suffer. This idea is not the reverse of the above idea: one says declining availability is caused by past financial difficulties; the other says low availability causes present financial problems. We tested the latter idea and it was not supported: the rate of return in a given year was not related to current availability in any systematic way.

This suggests that if a utility's earnings are squeezed, poor unit performance follows--although it takes a couple of years for this to become apparent in lower equivalent availability and higher heat rate, that is, higher costs to the ratepayer. Anyone who has been responsible for a budget or a business decision knows that this is what often happens in any industry: earnings fall, maintenance is skimped and equipment becomes less productive. Doubters are referred to the example of the New York City transit system:[11]

> The Metropolitan Transportation Authority of the State of New York "literally stopped preventative maintenance in 1975," when the city's fiscal crisis hit, says City Council President and MTA board member Carol Bellamy. The results were stark: The number of serious breakdowns en route rose to 12,291 in 1977 and tripled to an estimated 36,000 this year; and the number of miles traveled by the average subway car before having to be laid up for major repairs dropped from 13,627 in 1977 to 6,500 in 1981.

For the electric utility industry, it is possible to halt this declining trend in generating unit performance: obsolete or defective equipment can be replaced. Additional pulverizers can be installed to compensate for poorer quality fuel. Increases in maintenance expenditures could also be expected to improve unit performance. This brings us back to the basic regulatory question: What are appropriate performance standards?

V. SETTING APPROPRIATE PERFORMANCE STANDARDS

A major result of our analysis is that a performance standard, whether set internally by management or externally by a regulatory commission, should recognize the major differences among generating units. Moreover, if financial factors, such as rate of return do indeed affect generating unit performance, utility managers and commissioners should avoid incentives that could backfire and send a utility into a declining cycle of low availability, poor heat rates, high fuel costs and low returns on investment.

There is one other aspect of the NERA study involving standards. Our analysis showed a large variation in generating unit performance. Some of this variation can be explained by engineering factors and coal quality: our model explained 22 percent of the variation among annual equivalent availabilities of units ($R^2 = .22$). There are analysts who would argue that an R^2 of .22 is not very high. But size alone (the EEI/NERC characteristic for differentiating units) explains only 9 percent of the variation. Using the 10-year average rather than annual equivalent availability in our model increases the R^2 from .22 to .56, because the average smooths out some of the annual variation.

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[11] Business Week, October 26, 1981, p. 146.

The difference between the R^2s of the annual and 10-year average regressions carries important policy implications. It suggests that whatever performance "standard" regulators choose should be based on some kind of range. The size of the range should depend on the length of the period and number of units under consideration. The shorter the test period, the wider the range. Similarly as the number of units included in the average decreases,the wider the range. If a standard is set on a unit-by-unit and year-by-year basis, the range should be quite large. For example, for one specific individual unit in a single year, one standard deviation from the average (plus or minus) covers a range in availability from 43 to 78 percent.[12] One standard deviation from the mean for the same unit's 10-year performance would fall between 64 and 75 percent.

One further caveat: it is wrong to attribute the unexplained variation in models like these to "management". The unexplained variation is due to missing explanatory variables, one of which may be "management". But there are many other reasons: we did not include conversion to oil and reconversion to coal as a variable. Nor did we include Brown Boveri as a turbine manufacturer, because only one unit had such a turbine, and so on. The variables we did include had a significant effect on availability but together did not explain all the variation in unit performance. Inclusion of additional variables would no doubt explain more of the variation in performance.

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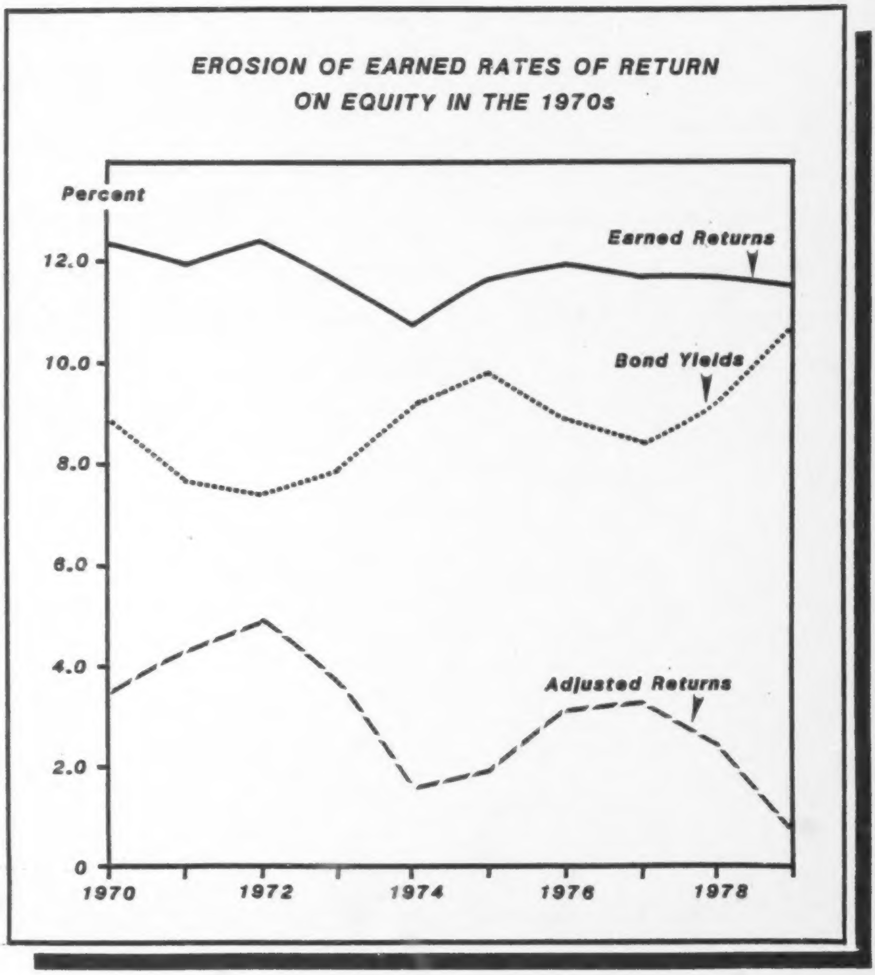
[12] This specific unit was a 14-year old subcritical unit with a positive pressure, Combustion Engineering boiler and a General Electric turbine-generator.

In the meantime, commissioners should not judge generating unit performance below an industry average as proof of management incompetence, nor performance above the average as evidence of merit. However, regulators should acknowledge the demonstrated relationship between a utility's earnings and the performance of that company's generating equipment.



EROSION OF EARNED RATES OF RETURN ON EQUITY IN THE 1970s

Figure 3

TABLE 1

EQUIVALENT AVAILABILITY
EEI/NERC TEN-YEAR AVERAGES
FUEL TYPE

1970 - 1979

Size of Generating Unit	Fuel-Type Coal (1)	 Oil (2)	 Gas (3)
	(Percent)		
200-574 MW	74.3%	77.0%	79.4%
575 + MW	68.2	69.2	72.8

Source: National Electric Reliability Council (NERC), Generating Availability Data System, Ten Year Review, 1970-1979 Report on Equipment Availability, 1980.

TABLE 2

RELATIONSHIP OF EQUIVALENT AVAILABILITY OF COAL UNITS TO VARIOUS UNIT, FUEL, AND FINANCIAL CHARACTERISTICS

	Explanation of Decline in Equivalent Availability Over Time			
	Age and Vintage		Earned Rate of Return on Equity	
Explanatory Characteristics	Coefficient (1)	t-Statistic (2)	Coefficient (3)	t-Statistic (4)
General Characteristics				
Vintage	-1.23	-6.15	-0.61	-1.16
Age	-1.36	-7.80	-0.79	-1.56
Size [1]	2918.65	5.17	2323.58	3.47
Boiler Design				
BD1 [2]	4.56	4.75	5.82	5.22
BD2 [3]	-1.43	-0.76	0.23	0.11
BD3 [4]	-7.86	-2.61	-10.31	-3.06
Cyclone	-4.48	-2.74	-3.85	-1.99
Once-Through [5]	-5.86	-4.74	-5.68	-4.02
Boiler Manufacturers				
Babcock & Wilcox	5.17	3.86	4.50	2.92
Combustion Engineering	4.06	3.38	4.73	3.46
Turbine-Generator Manufacturers				
General Electric	5.64	2.64	3.98	1.59
Westinghouse	3.44	1.59	2.13	0.84
Fuel Characteristics				
MBtu Content	0.30	1.84	0.58	2.72
Sulfur Content	-53.69	-1.09	-156.74	-2.58
Ash Content	4.44	0.38	-0.66	-0.04
Moisture Content	-13.75	-1.64	-35.25	-3.58
Financial Characteristics [6]				
Earned Rate of Return on Equity				
1971			1.89	3.33
1972			1.46	2.96
1973			2.32	5.21
1974			1.69	4.38
1975			2.00	4.52
1976			2.43	4.17
1977			2.21	2.49
Constant	146.36		98.07	
Number of Observations	1,201		358	
$\bar{R}^2$	0.24		0.22	
Standard Error of Estimate	13.73		14.08	

[1] "Size" is expressed as the reciprocal of nameplate capacity.

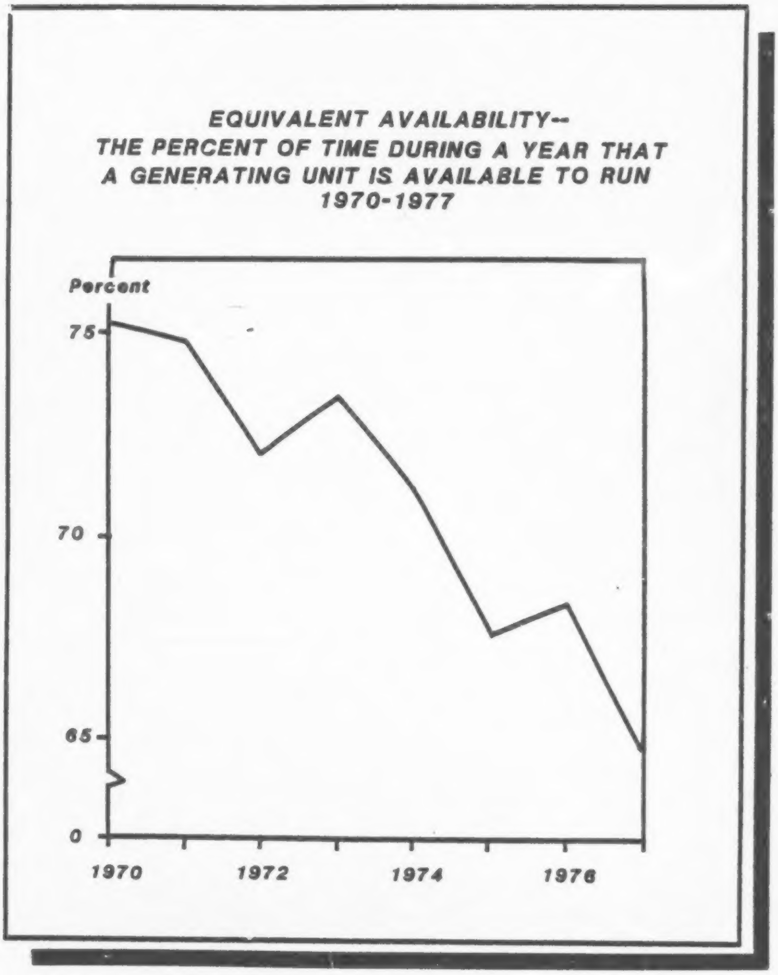
[2] "BD1" is equal to 1 if unit is balanced draft, otherwise it is equal to 0.

[3] "BD2" is equal to 1 in the years following conversion from positive pressure to balanced draft.

[4] "BD3" is equal to 1 in year of conversion from positive pressure to balanced draft.

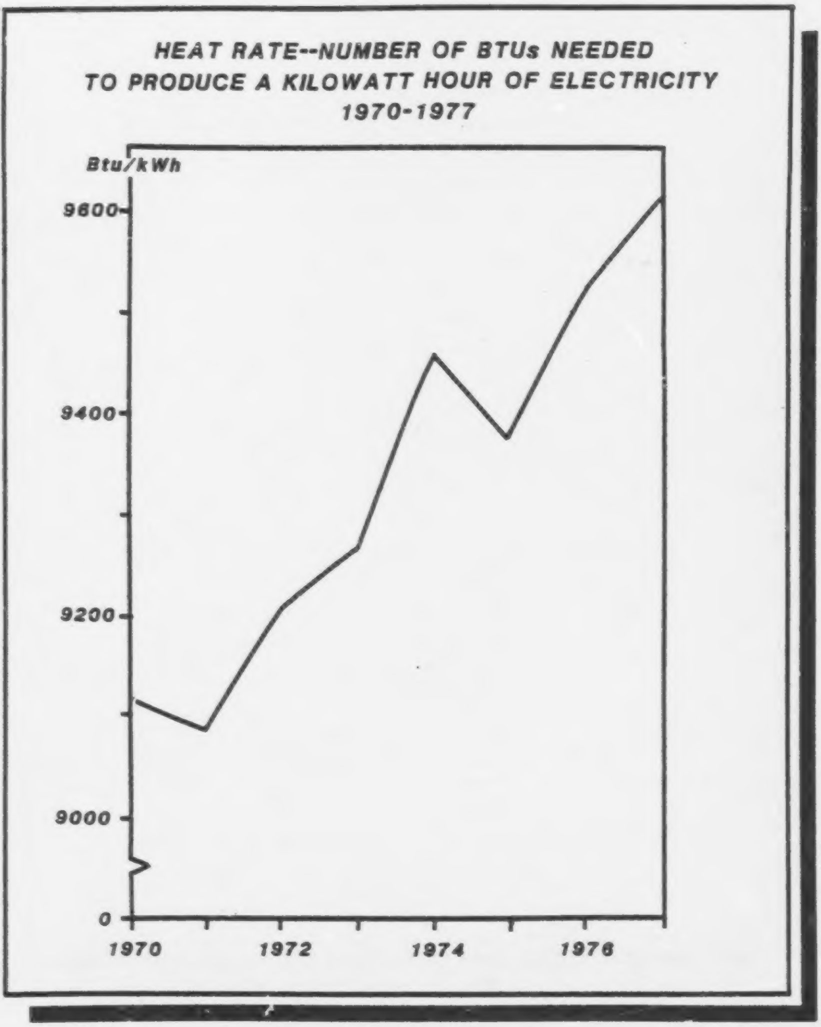
[5] "Once-Through" consists of subcritical once-through and supercritical.

[6] Three-year moving average, lagged one year, deflated by a three-year moving average of return on new issue long-term utility bonds.



EQUIVALENT AVAILABILITY--
THE PERCENT OF TIME DURING A YEAR THAT
A GENERATING UNIT IS AVAILABLE TO RUN
1970-1977

Figure 1



HEAT RATE--NUMBER OF BTUs NEEDED TO PRODUCE A KILOWATT HOUR OF ELECTRICITY 1970-1977

Figure 2

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HEAT RATES AND AVAILABILITY: THE USE OF ECONOMETRIC ANALYSIS IN COMPARING ELECTRIC GENERATING UNIT PERFORMANCE

by

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I. INTRODUCTION

The purpose of this study is to develop econometric models which explain and which can be used to compare performance of large electric generating units over time and across the United States. Ideally, such a study should take into account the age, size and vintage of the generating unit, economic factors and engineering design characteristics. To date, two of these considerations have been tackled separately: there are many studies which look at size, age and vintage and there are many that examine engineering characteristics. We know of no study which attempts to incorporate economic factors. Econometric analysis enables us to consider all three simultaneously. Moreover, it permits us to quantify the effects of a single variable, taking everything else into consideration—and hence, to estimate expected values of performance for units of specified characteristics. It also enables us to define a range of expected performance for similar units.

The use of econometric modeling to compare performance represents a significant departure from the two types of studies of unit performance which have been done: the engineering study and the comparison group study. It is a departure in two ways: the data are much broader-based and the analysis is more statistically sophisticated.

The engineering studies generally analyze generating unit outages by type of outage, e.g., outage due to boiler tube leaks or generator failures.[1] The outages are then related to the design characteristics of the relevant equipment in the generating unit. These studies, which have been done in great detail for

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[1] S. M. Stoller Corporation, principal investigators R. H. Koppe and E. A. J. Olson, Nuclear and Large Fossil Unit Operating Experience, prepared for Electric Power Research Institute, September 1979.

EPRI to help pinpoint causes of outages, have provided an invaluable basis for the present study. The results of these analyses can be presented as cross-tabulations by type of outage and equipment design characteristic. However, the effect of the particular engineering design characteristic with other factors held constant has not yet been computed.

A second type of study develops comparison groups comprised of generating units roughly comparable to the specific unit of interest.[2] Frequently, "standards" are defined as the group average for the particular performance index under examination. In contrast to the engineering study, the performance indices are aggregate annual measures such as equivalent availability.[3] The comparison group studies suffer from two main weaknesses. First, the criteria used to assign units into comparison groups must, of necessity, be based on only a few characteristics; as the number of characteristics increases, the number of units which can be classified as similar decreases. It is unsatisfactory to base a standard of performance on the average value of an index for very few units because the average is, then, extremely sensitive to the behavior of any one unit. Second, the criteria generally used by these studies to set up comparison groups are based on a few broad characteristics of the generating unit such as age, size, vintage and type of fuel burned. As the results of the present study show, these broad characteristics do not adequately explain the factors affecting performance. For example, the effect of unit size on equivalent availability is due to a number of engineering design and operating factors which vary with size, and is not due to any inherent size effect. Also, the apparent effects of age and vintage may be due to other time trend variables.

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[2] Report by Ralph Renken, A. T. Kearney Co., to the Public Staff of the North Carolina Utilities Commission on VEPCO's Management in Controlling Power Generation Productivity, Docket No. E-22, Sub 257, Exhibit A, May 18, 1981.

[3] Roughly defined, equivalent availability is the percent of time over a year that a generating unit is available to run at full capability. For a strict definition, see National Electric Reliability Council, Generating Availability Data System, Ten-Year Review, 1970-1979, Report on Equipment Availability, 1980, pp. 83-85.

The econometric models presented in this study can be seen as a more sophisticated form of comparison group analysis. First, the sample size is larger, providing a more reliable basis upon which to calculate standards. Second, the major design and operating factors affecting unit performance can be included in such models in addition to general characteristics of the unit. The factors included in the models are boiler and turbine-generator design characteristics, fuel quality and financial characteristics, as well as age, vintage and size.

Econometric models cannot replace engineering studies. They can, however, be used to test and quantify engineering judgments about the relationship of design and operating characteristics to performance. Econometric models are compatible with engineering analyses, although as yet the data required to develop econometric models fully paralleling engineering analyses are not available on an industry-wide basis. Nonetheless, the results of econometric models of both equivalent availability and heat rate generally corroborate hypotheses which are derived from engineering principles.

We believe that the econometric analysis we have developed and present in this study accomplishes the following: (1) It provides a more satisfactory methodology for comparing equivalent availability of generating units than comparison group analysis. (2) It fills a substantial gap in the analysis of heat rates[4] in that it is the only study we know of which covers all large coal-fired units. (3) It enables the researcher to estimate a range of performance, which studies using more limited data and methods do not.

II. SPECIFICATION AND ESTIMATION RESULTS OF THE MODELS OF EQUIVALENT AVAILABILITY AND HEAT RATE

A. Specification of the Models

NERA developed two analyses of generating unit performance: one of annual unit equivalent availability and one of annual unit heat rate. Variables used to explain unit performance included engineering design, age, size, vintage, fuel quality, and financial characteristics. The models of equivalent availability and heat rates were based on data from a sample of large coal-fired units. The sample was limited to units larger than 200 megawatts, built between 1960 and 1974, burning coal in at least three years. There were 171 such units, and these were operated by 57 different utilities.

For the models of equivalent availability, historical data on equivalent availability of the units for the period 1969-1977 were derived from two EEI/NERC data tapes. Incidentally, a comparison of the tapes, one of which is merely an updated version of the other, indicated great inconsistencies in the data. Therefore, before using the data, we resolved the inconsistencies, in many cases with the help of utility plant managers.

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[4] Heat rate is the amount of fuel (Btus) needed to produce one kilowatt-hour of electricity. There is a distinction between net and gross heat rates. Net heat rates are calculated as the ratio of total Btus of input fuel to kilowatt-hours of electricity sent out, i.e., excluding electricity used by the generating unit or plant. Gross heat rates include electricity used in-house in the denominator.

For the heat rate model, historical data on the net heat rates of the 171 units were not publicly available.[5] But, we were able to compute gross annual unit heat rates for the period 1969-1977, using a variety of published data sources.

Once we had data for the two performance measures that we were trying to explain, we consulted various published performance studies and talked with numerous engineers around the country to determine those characteristics which heavily affect generating unit performance. Our inquiry in this area indicated that certain built-in engineering features and the quality of coal were important factors in explaining equivalent availability and heat rate.[6] The list of other relevant factors was longer than the list of factors for which data were obtainable. (See Table 1.) For coal characteristics, we were able to obtain data on heat, sulfur, ash and moisture content. Data on other coal characteristics, such as ash softening temperature, viscosity and grindability, which are important in explaining performance, could not be obtained. For the built-in engineering features, we were able to obtain data on boiler design, the boiler manufacturer and the turbine-generator manufacturer.

Some standard statistical measures are presented with the regression results of the models: (1) the t-statistics for the regression coefficients and (2) a goodness-of-fit measure for the regression.[7] With few exceptions, the t-statistics of the included variables are greater than 2.0, indicating the coefficients are significantly different from zero at a 95 percent confidence level.

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[5] Unit-specific net heat rate data are not systematically available. Net heat rate data are reported only for units which are the best performers on a system, i.e., the best generating units for which over 50 percent of their capacity was used over the year, on the FPC/FERC Form 1.

[6] The specific factors relevant to explaining performance varied, depending upon which measure was being modeled.

[7] The goodness-of-fit measure equals -2 multiplied by the log of the likelihood ratio which has a chi-square distribution with degrees of freedom equal to the number of parameters estimated.

We now turn to a discussion of the regression results of the equivalent availability and heat rate models, respectively. In order to help the reader distinguish the various models, here is a summary table specifying the variables and the form used in each model discussed below.

Name	Dependent Variable (1)	Specification of Dependent Variable (2)	Independent Variables (3)
Equivalent Availability (E.A.)			
Comparison Group	EA	Double Truncated Normal	Size, Age, Vintage
Model I	EA	Double Truncated Normal	Same as Comparison Group plus Engineering and Coal Quality Variables
Model II	EA	Double Truncated Normal	Same as Model I plus Financial Variable
Heat Rate (H.R.)	Gross H.R.	Untransformed	See Text.

B. Results of the Model of Equivalent Availability

Three models were estimated to explain equivalent availability. The first model was set up to parallel the comparison group analyses. While specific comparison groups were not set up, age, size and vintage, which are traditionally used as criteria to develop comparison groups, were used as explanatory variables in this model. The other two models contain an expanded set of regressors. They differ from each other in their explanation of the strong decline in equivalent availability over the sample period. The first of these models posits that the decline in equivalent availability is comprised of two components: age and vintage. The second posits that this declining trend is due to the eroding financial position of the utilities over the sample period.

1. The Form of the Model

Before discussing the results of the equivalent availability models, a brief explanation of the appropriate functional form is needed. Since equivalent availability is a limited dependent variable, several specifications appropriate to this type of dependent variable were tested.[8] We obtained the best statistical results for the double truncated normal regression model. The double truncated normal regression model is appropriate in cases in which the dependent variable, in an otherwise classical regression model, is truncated both from above and below.[9] In the case of equivalent availability, the upper bound is 100 percent and the lower bound is zero percent.

2. Results of "Comparison Group" Model

In the first column of Table 2, we present the double truncated normal regression results for the model which relates equivalent availability to a few general unit characteristics, namely, vintage, age and size (hereinafter referred to as "Comparison Model"). In the second and third columns of that table, we present the regression results for the two fully-specified models, hereinafter referred to as Models I and II, respectively. In addition to the general unit characteristics, we have included variables on engineering and coal characteristics in Model I. In addition to the variables included in Model I, Model II includes financial characteristics of the utility. Comparing the results of Model I and Model II to the Comparison Model, we limit our discussion mainly to those variables which are included in the Comparison Model, namely, size, age and vintage. We discuss the results for all the regressors in Models I and II in subsequent sections.

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[8] Among the models tested were the logit and probit models.

[9] For an explanation of this model see, Dale J. Poirier and Angelo Melino, "A Note on the Interpretation of Regression Coefficients Within a Class of Truncated Distributions," Econometrica, September 1978.

Comparing the results of the Comparison Model with Models I and II, the coefficients for age and vintage are remarkably similar. Size of the unit is the one variable for which the coefficient differs. The reason for the difference is that some of what appears to be the effect of size is really the effect of once-through boilers, a variable which has been explicitly included in Models I and II. Comparing the explanatory power of the models (as measured by the goodness-of-fit measure), it is greater in Model I and Model II than in the Comparison Model. Furthermore, the coefficients of the variables included in Models I and II but not included in the Comparison Model are significant in most cases. The difference in the models demonstrates the superiority of a fully-specified econometric model over a comparison group analysis.

However, the more interesting aspects of Model I and II are the interpretation of the results for the engineering and financial characteristics and it is to these we turn our attention. It should be noted that the regression coefficients from the double truncated regression are not directly interpretable. In order to obtain the partial effect on equivalent availability of change in the independent variable, the coefficient must be multiplied by a constant.[10] The results discussed below reflect this adjustment.

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[10] This constant is the ratio of the truncated variance of equivalent availability to the untruncated variance.

3. Results of Model I

The results of Model I are as follows:

a. Furnace Design Variables

The model results suggest that units with dry-ash furnaces had higher availabilities than those with cyclone (slag-tap) furnaces. This result corroborates expectations since dry-ash units are easier to maintain than cyclone units, where the ash remains as wet slag and causes greater wear in the boiler. Typically, equivalent availability of dry-ash furnaces was 4.4 percentage points higher than that of cyclone furnaces.

Balanced draft furnaces performed better than positive pressure furnaces. This result again supports expectations since balanced draft furnaces do not have the problem of coal ash accumulation in the unit (or plant) that positive pressure boilers do. If the generating unit was built with a balanced draft furnace, its availability was 5.2 percentage points higher than a positive pressure unit. Given the demonstrably better performance by balanced draft units, a number of units have been converted from positive pressure to balance draft furnaces. In order to incorporate the conversion effect in the model, two variables were specified. The first variable measured the effect on equivalent availability of physically converting the unit. It equalled one in the year of conversion and zero in all other years. The second variable was included to measure the "improvement" in performance following the conversion. It equalled zero up to and including the year of conversion and one in the years following the conversion. As expected, the coefficient of the first variable was negative, implying that some downtime was required to convert the unit. The coefficient on the second variable was negative, but not significantly different from zero, implying virtually no change in performance after conversion. This result was contrary to our expectations. One explanation could be that our data only extend through 1977, and include only a few years of performance after conversions, many of which took place between 1974-1977.

b. Boiler and Turbine-Generator Variables

The only types of boiler circulation included in these regressions were once-through versus recirculating. While data for the sample units were available for a more disaggregate breakdown of circulation type (see Table 1), the number of units in these classes was too small to draw reliable inferences. However, there were sufficient data to model the most important classification of circulation type, namely, once-through versus recirculating boilers. The availability of recirculating units is greater (by roughly 6 percentage points) than that of once-through units. This may be explained by the fact that once-through boilers are more difficult to maintain, since water in the boiler tubes contains more impurities than water in recirculating boilers. Another possible explanation is that the group of once-through boilers is dominated by supercritical (pressure) boilers. Historically, technological problems have prevented supercritical boilers from performing as well as subcritical ones.

Finally, both turbine-generator and boiler manufacturers were included in the model. The availability of General Electric turbine-generators was better than that of Westinghouse (by roughly 2 percentage points). (This could be due to differences in the design of the turbine and generator but the data necessary to make that determination were unavailable at the time of the study.) The differences in performance among different manufacturers boilers cannot be explained solely by quality differences in products among them. There are also differences in the design and types of boilers among manufacturers. For example, only Combustion Engineering manufactures tangential dry-ash furnaces.[11] Also, in our sample, all controlled recirculating units were manufactured by Combustion Engineering. Therefore, the Combustion Engineering coefficient may reflect either the quality of Combustion Engineering boilers or the fact that a large portion of them are tangential furnaces and controlled recirculating boilers.

c. Coal Characteristics

As a group, the variables on coal characteristics are the least satisfactory among the groups of variables included in the model. Theoretically, the characteristics of the coal burned in the unit should be compared with the characteristics of the coal which the unit was designed to burn. However, only data on the characteristics of the coal the unit actually burned, and not what it was designed to burn, were available. The coal characteristics included in the model were the chemical composition of the coal actually burned in the unit in a particular year. These characteristics included: ash, sulfur, moisture and heat content of the coal. While these measures are descriptive for sulfur, moisture and heat content of the coal, the ash content of the coal does not describe the slagging potential of the coal, the chief problem caused by ash.

Sulfur content can reduce unit performance because of corrosion, slagging and fouling in the boiler. The model indicates that for each percent increase in sulfur content, availability is reduced by 0.6 percentage points. Moisture adversely affects performance: for each percent increase in moisture, availability is reduced by 0.2 percentage points. The heat content of the coal has a positive effect on availability. The regression coefficient of percent ash is not significantly different from zero. As noted, this is not the sole characteristic of ash affecting availability.

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[11] Tangential furnaces refers to a type of firing design in which the burners are in opposing corners of the furnace.

d. General Characteristics

Engineers have found that coal-fired units have lower availability in the first year of operation when compared to the second to fourth years of operation, and then decreasing availability in the following years. Unfortunately, specifying the age variable as such in the model does not work as well as an age variable which increases each year. The estimated effect of age using the latter age specification is a decrease in equivalent availability of 1.5 percentage points each year. To the extent age is capturing the effects of time trends in missing variables, the trends of the missing variables dominate specific age effects.

The coefficient of generating unit size indicates that larger size brings reduced performance in the range from 200-500 megawatts. Above 500 megawatts, the effect of size on equivalent availability appears negligible. The effect of size may reflect the effects of the increased complexity of equipment and consequent maintenance, as unit size increases.

Finally, the coefficient of vintage indicates that units of more recent vintage do not perform as well as older vintage units. This may reflect the possibility that newer units are first generations of new technologies, such as supercritical units which still have design problems.

4. Results of Model II

Model II of equivalent availability includes the variables in Model I and also a variable which describes the financial condition of the utility, as measured by the adjusted rate of return on equity (ROE). The ROE is defined as the earned rate of return on equity adjusted for (less) the yield on newly issued long-term utility bonds. The relevant ROE variable in any year is the three-year moving average for the three years prior. The ROE was tested on the annual cross-sectional data for each year from 1970-1977, to determine if ROE had a role in explaining equivalent availability apart from its ability to explain the declining trend in the data.

In general, the coefficients of the engineering design characteristics are similar in Model I and Model II (for those coefficients which are statistically significant). The major difference between the two models is in the coefficients of the age, vintage and fuel characteristics. As expected the inclusion of the ROE variable reduced the age and vintage effects, since ROE exhibits a strong trend over our sample period. The only other variables included in the model whose values changed over time were the fuel characteristics. The inclusion of the ROE had an effect on their coefficients, increasing their absolute values and their statistical significance.

The coefficient of ROE was stronger during the 1975-1977 period than in the 1971-1974 period. The coefficients averaged 1.87 in the period 1971-1974 and averaged 2.08 in the period 1975-1977. The change in the coefficients over the two time periods parallels the change in the riskiness of utility stock and fuel market conditions between the two periods. The coefficients suggest there is an association between high ROE and subsequent availability. All the ROE coefficients were statistically significant. We obtained similar coefficients for ROE in the annual cross-section models.

C. Results of the Model of Heat Rates

1. Design Heat Rates[12]

The relationship between heat rate and output is determined by laws of physics which describe the change from heat energy to work energy. A design heat rate curve of a generating unit describes the relationship between the heat rate of the unit and its output of electricity. The curve is usually approximated by a hyperbolic function. Specifically, unit heat rate is inversely related to unit output. Mathematically this approximation of the unit heat rate curve can be written as:

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[12] See Shields, C., Boilers--Types, Characteristics and Functions (McGraw Hill Book Co.: New York, 1961).

$$HR_i = a_i + \frac{b_i}{x_i}$$

Where HR_i = heat rate of unit i

x_i = output of unit i (can be expressed relative to the maximum capability of the unit.)

a_i = upward displacement parameter for unit i

b_i = curvature parameter for unit i.

The values of the parameters of the heat rate curve depend on the engineering design of the unit. For purposes of the heat rate model, we have assumed that b_i is constant across units regardless of design.[13] The displacement parameter, a_i, is assumed to vary across units due to differences in engineering design and is assumed to vary for an individual unit over time due to aging. The above assumptions concerning the coefficients of the heat rate curve lead to the following model specification. Specifically, a_i can be described as:

a_{it} = $f(E_i, Z_{it})$

where: a_{it} = upward displacement parameter for unit i in year t

E_i = variables affecting heat rate which do not change over time, for unit i

Z_{it} = variables affecting heat rate which change over time, for unit i.

We assume:

b_i = b for all units for all years in our sample.

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[13] We have tested this hypothesis using design heat rate curves on all fossil-fired units in VEPCO's service area.

2. Regression Results

a. Feedwater Pump Drivers

Turning to the regression results on Table 5, one variable affecting gross but not net heat rates is the type of energy used to drive the feedwater pumps: electricity, shaft, steam or other. If the feedwater pump is shaft- or steam-driven, then energy is drained from the unit to run the pump before being converted to electricity. Heat rates computed for these units would be higher (less efficient). A variable defining the type of fuel used to drive the feedwater pump was explicitly included as an independent variable to take account of this problem. As expected, shaft- and steam-driven units have higher heat rates than motor-driven units. It is not clear what types of fuel drive the feedwater pumps for units in the "other" category. Nonetheless, this category was included separately so the other feedwater fuels would not capture its effect.

b. Boiler and Furnace Design Variables

The boiler design variables which were significant in explaining real rates are supercritical boilers and cyclone furnaces. Both these variables reflect major technological designs which would shift the unit design heat rate curve. As expected, the heat rate curve for a supercritical unit would be below that of a subcritical unit (indicating greater efficiency). Supercritical units are designed to have lower heat rate curves than subcritical units. Cyclone furnaces appear to have upwardly-shifted curves.

c. Fuel Characteristics

The fuel characteristics included in the model are the primary fuel burned in the unit and the chemical composition of the coal if coal is the primary fuel.[14] Some units in the sample converted from coal to oil, or converted from coal to oil and then back to coal again. The heat rate curve of coal-fired units which had converted to oil was found to be higher (less efficient) than that of units which had burned only coal. (The effect of converting from coal to oil was not apparent when tested in the equivalent availability model.) The effect on heat rates (or availability) of reconverting back to coal again could not be measured because within the sample period, only two units had done so.

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[14] A fuel is considered a primary fuel if it accounts for greater than 30 percent of the total fuel burned in the unit.

The second set of fuel characteristic variables included in the heat rate model relates to the chemical composition of the coal (when coal is the primary fuel). Specifically, the ash and moisture content of the coal were included as independent variables. Both ash and moisture increase the heat rate. Greater levels of ash may be correlated with more slagging, which reduces heat transfer. (However, we should have obtained a similar result in the equivalent availability model as well.) Higher levels of ash may also constrain pulverizer capacity, thereby forcing the unit to run at less than original capacity. Greater moisture levels imply lower actual Btus available to produce electricity, since some Btus are consumed in evaporating the moisture from the coal.

d. General Characteristics

Finally, some general unit characteristics were included in the model. As in the equivalent availability model, age and vintage were included. The effect of unit size on heat rate was tested and found insignificant. The main effect of unit size appears to be captured by the supercritical variable. The effect of both vintage and age on heat rate is positive. The role of vintage on heat rate may be linked to the generations of technologies represented by the sample units. The age effect appears to be related to the increase in heat rates (decrease in efficiency) over time. As in the equivalent availability model, age and vintage may also be capture some effects of trends in utility financial conditions. However, unlike the equivalent availability model, it is not clear to what extent heat rates can be improved beyond the original design curve even if additional funds were available. Consequently, even though ROE has the expected sign and is statistically significant when included in the heat rate model, we are still checking the validity of its inclusion in this model.

e. Output Factor

As noted earlier, the unit heat rate is inversely related to its output. Therefore, the reciprocal of output factor was included as an independent variable. The coefficient for this variable was roughly 115,000. Since we had design curves for all of VEPCO's fossil units, we used these data to test the hypothesis that b_i was constant for all types of units. Most of the unit heat rate curves had b values between 80,000 and 160,000. Our estimate of b is roughly the midpoint of this range.

D. Standards of Performance—Using the Results of the Models of Equivalent Availability and Heat Rate

The final product of this study is the development of performance standards for equivalent availability and heat rates against which a specific unit's performance could be evaluated. The purpose of estimating equivalent availability and heat rate models was to provide a tool with which to do this. By specifying the values of the independent variables for a specific generating unit, the models can be used to predict the expected value or "average" of the performance standard of interest.

While the predicted value of the model is the most likely value, given both the statistical error of the model and the measurement error in the equivalent availability data, and the fact that all possible explanatory factors affecting unit performance can never be included in such models, the researcher is interested in a range of likely predicted values. Specifically, he is interested in the range of values within which he can assert, with a specific degree of confidence that the true value of performance lies. The greater the degree of certainty desired, the wider the range of values. Obviously, the types and magnitudes of the policy questions to be answered using the model predictions determine the degree of confidence desirable.

It should be noted that while the econometric model approach allows a range around its average, the comparison group analysis, which is based on fewer variables and data points, seldom relies on any statistic other than the group mean.

IV. CONCLUSIONS

To date most of the statistical studies of generating unit performance--engineering studies and comparison group analyses--have been used to determine performance standards. Econometric models can also be used for the same purpose. But any statistical comparison should be used with caution. The econometric models described in this report take into account many factors for which industry data are available, and these factors can be seen to have a significant effect on performance. To that extent, this study parallels and expands engineering studies. It shows, we believe for the first time, the impact on equivalent availability and heat rate of fuel quality, engineering design and financial factors, as well as the variables included in the comparison group analyses. In that sense, this study represents a considerable improvement over comparison group analyses.

There are, however, other factors affecting performance for which data are not available. Were these to be taken into account also, the values predicted for individual units might well change significantly. Among the variables we believe to be significant, but which we have had to omit are:

conversion to coal, boiler sizing, design fuel quality, excess fuel costs and ash softening temperature. The relatively large residuals in our analysis are partly due to large random variations in annual data, partly due to missing variables and partly due to utility management.

There is a temptation to attribute all unexplained variance to management, particularly when a statistical analysis is used to set standards of performance. This is clearly not the case. A large part of the annual variation is random, and a large part of the unexplained variation beyond that is due to omitted variables. The present study goes a long way beyond the previous work in explaining the variation in performance: future researchers may be able to extend and refine our results.

TABLE 1
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SPECIFICATION OF THE MODEL

I. GENERAL CHARACTERISTICS

Ideal Set	Actual Set
1. Age	1. Age
2. Size	2. Size
3. Vintage	3. Vintage
a) Technology Changes (see -ENGINEERING DESIGN PARAMETERS).	
b) Maturation of a Technology	
4. Variability of Load	4. Output Factor

II. ENGINEERING DESIGN PARAMETERS

A) Pulverizers

Ideal Set	Actual Set
1. Pulverizer Capacity	1. Percent Moisture of Coal Actually Burned
2. Type of Coal that Pulverizer Designed For:	
a) Grindability	
b) Percent Moisture	

B) Boilers and Auxiliary Equipment

Ideal Set	Actual Set
1. Design Heat Release Rate of Unit	1. Dry-Ash or Slag-Tap Furnace
2. Dry-Ash or Slag-Tap Furnace	2. Balanced Draft or Positive Pressure Furnace
3. Balanced Draft or Positive Pressure Furnace	3. Type of Circulation
4. Type of Circulation	a) Recirculating
a) Recirculating	i) Natural
i) Natural	ii) Controlled
ii) Controlled	b) Once-Through
b) Once-Through	i) Subcritical
i) Subcritical	ii) Supercritical
ii) Supercritical	4. Boiler Manufacturer
5. Boiler Manufacturer	5. Feedwater Pump by Fuel Type
6. Feedwater Pump by Fuel Type	

C) Turbine-Generators

Ideal Set	Actual Set
1. Turbine-Generator Manufacturer	1. Turbine-Generator Manufacturer

TABLE 1
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SPECIFICATION OF THE MODEL

III. COAL QUALITY

Ideal Set

1. Ash
    - a) Ash Softening Temperature--Design vs. Actual
    - b) Viscosity of Coal-Ash Slag
2. Sulfur
    - a) Percent Sulfur in Coal
    - b) Flue Exit Gas Temperature vs. Dewpoint
3. Moisture (see Pulverizers)
4. Grindability (see Pulverizers)
5. Btu Content

Actual Set

1. Ash
    - a) Percent Ash in Coal Actually Burned
2. Sulfur
    - a) Percent Sulfur in Coal
3. Btu Content

IV. FINANCIAL CHARACTERISTICS

Ideal Set

1. Total Operation and Maintenance Expenditures
2. Additions to Capital
3. Allowed and Earned Rate of Return on Equity

Actual Set

1. Earned Rate of Return on Equity (deflated by return on utility bonds)

TABLE 2

REGRESSION RESULTS[1] FOR EQUIVALENT AVAILABILITY MODELS

Independent Variable	Comparison Model		Model I		Model II	
	Coefficient[2] (1)	t-Statistic (2)	Coefficient[3] (3)	t-Statistic (4)	Coefficient[4] (5)	t-Statistic (6)
General Characteristics						
Vintage	-1.50	-5.83	-1.55	-5.90	-0.53	-0.85
Age	-1.73	-7.39	-1.73	-7.70	-0.82	-1.34
Size[5]	6,307.10	11.08	3,681.00	5.64	3,051.00	4.13
Boiler Design						
BD1[6]			6.02	5.22	7.16	5.46
BD2[7]			-1.12	-0.47	0.77	0.29
BD3[8]			-8.72	-2.16	-11.33	-2.47
Cyclone			-5.14	-2.42	-4.27	-1.76
Once-Through[9]			-7.01	-4.93	-6.65	-4.18
Boiler Manufacturer						
Babcock & Wilcox			6.36	4.09	5.34	2.92
Combustion Engineering			4.90	3.52	5.62	3.52
Turbine-Generator Manufacturer						
General Electric			7.05	2.66	4.54	1.56
Westinghouse			4.51	1.72	2.66	0.92
Fuel Characteristics						
MBtu Content			0.35	1.53	0.62	2.25
Sulfur Content			-69.67	-1.14	-183.31	-2.43
Ash Content			9.50	0.63	2.61	0.15
Moisture Content			-18.11	-1.61	-41.76	-3.22
Financial Characteristics Earned Rate of Return on Equity[10]						
1971					2.08	3.22
1972					1.76	2.79
1973					2.79	4.77
1974					1.95	4.12
1975					2.28	3.88
1976					2.69	3.46
1977					2.19	2.15
Constant	168.02	8.88	167.95	8.77	90.79	1.98
Number of Observations	1,203		1,203		960	
χ^2_{df}	218.54		340.60		242.32	

Note: *df* = number of parameters estimated minus one.

[1] Results based on the double truncated normal regression model.

[2] To obtain marginal effects on equivalent availability evaluated at regressor means, multiply coefficients by 0.828.

[3] To obtain the marginal effects on equivalent availability evaluated at the regressor means, multiply coefficients by 0.855.

[4] To obtain the marginal effects on equivalent availability evaluated at the regressor means, multiply coefficients by 0.871.

[5] "Size" is expressed as the reciprocal of nameplate capacity.

[6] "BD1" is equal to 1 if unit is balanced draft, otherwise it is equal to 0.

[7] "BD2" is equal to 1 in the years following conversion from positive pressure to balanced draft.

[8] "BD3" is equal to 1 in year of conversion from positive pressure to balanced draft.

[9] "Once-Through" consists of subcritical once-through and supercritical.

[10] Three-year moving average, lagged one year, deflated by a three-year moving average of return on new issue long-term utility bonds.

ATTACHMENT B
(MRC EXH ___)

HEAT RATES AND AVAILABILITY:
THE USE OF ECONOMETRIC ANALYSIS IN COMPARING ELECTRIC GENERATING UNIT PERFORMANCE

Prepared for

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I. INTRODUCTION

The purpose of this study is to use statistical methods to compare performance of large electric generating units over time and across the United States. Ideally, such a study should take into account age, size and vintage of the unit, economic factors and specific engineering parameters. To date, two of these considerations have been tackled separately: there are many studies which look at size, age and vintage and there are many that examine engineering parameters. We know of no study which attempts to incorporate economic factors. Econometric analysis enables us to consider all three simultaneously. Moreover, it permits us to quantify the effects of a single variable, taking everything else into consideration—and hence, to estimate expected values of performance for units of specified characteristics. It also enables us to define a range of either expected or actual performance for similar units.

The use of econometric modeling to compare performance represents a significant departure from the two types of studies of unit performance done to date: the engineering study and the comparison group study. It is a departure in two ways: the data are much more broader based and the analysis is more statistically sophisticated.

The engineering studies generally analyze unit outages by type of outage, e.g., outage due to boiler tube leaks or generator failures.[1] The outages are then related to the design characteristics of the relevant equipment in the generating unit. These studies, which have been done in great detail for EPRI to help pinpoint causes of outages, have provided an invaluable basis for the present study. The results of these analyses can be presented as cross tabulations by type of outage and equipment design characteristics. However, the effect of the particular design characteristic with other factors held constant has not yet been computed.

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[1] S. M. Stoller Corporation, principal investigators R. H. Koppe and E. A. J. Olson, Nuclear and Large Fossil Unit Operating Experience, prepared for Electric Power Research Institute, September 1979.

A second type of study develops comparison groups comprised of generating units roughly comparable to the specific unit of interest.[2] Frequently, "standards" are defined as the group average for the particular performance index of interest. In contrast to the engineering study, the performance indices are aggregate annual measures such as equivalent availability. The comparison group studies suffer from two main weaknesses. First, the criteria used to assign units into comparison groups must, of necessity, be based on only a few characteristics since, as the number of characteristics increases, the number of units which can be classified as similar decreases. It is unsatisfactory to base a standard of performance on the average value of an index for very few units because the average is extremely sensitive to the behavior of any one unit. Second, the criteria generally used by these studies to set up comparison groups are based on a few broad characterizations of unit design such as age, size, vintage and fuel burned. As the results of the present study show, these broad characterizations do not adequately explain the factors affecting performance. For example, the effect of unit size on equivalent availability is due to a number of design and operating factors which vary with size, not to any inherent size effect. Also, the apparent effects of age and vintage may be due to other trended variables.

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[2] Report by Ralph Renken of A. T. Kearney to the Public Staff of the North Carolina Utilities Commission on VEPCO's Management in Controlling Power Generation Productivity, Docket No. E-22, Sub 257, Exhibit A, May 18, 1981.

The econometric models presented in this report can be seen as an advanced form of comparison group analysis. First, the sample size is larger, thus providing a more reliable basis upon which to calculate standards. Second, in addition to general characteristics of the unit, the major design and operating factors affecting unit performance can be included in such models. The factors included in the models are boiler and turbine-generator design characteristics, fuel quality, and financial characteristics as well as age, vintage and size.

Econometric models cannot replace engineering studies: they can be used to test and quantify engineering judgments about the relationship of design and operating characteristics to performance. Econometric techniques are compatible with engineering analyses, although as yet the data required to develop econometric models fully parallel to engineering analyses are not available on an industry-wide basis. Nonetheless, the results of statistical models of both equivalent availability and heat rate generally corroborate hypotheses which are derived from engineering principles.

We believe that the econometric analysis we have developed and present in this report has accomplished the following: (1) It provides a more satisfactory methodology for comparing equivalent availability than comparison group analysis. (2) It fills a substantial gap in analysis of heat rates in that it is the only study we know of which covers all large coal units. (3) Econometric studies enable the range of performance to be adequately estimated, which studies using more limited data and methods do not.

The remainder of this report will be organized as follows. Section II contains the development and specification of the statistical models of equivalent availability and heat rate. The key points in this section are (1) a brief layman's description of the design and operation of a generating unit, which provides a framework for understanding how these factors affect performance and, (2) a summary of the variables tested in the models. Section III then contains the results of the model. Here the discussion focuses on how well the model results match *a priori* expectations. This section concludes with a discussion of performance predictions based on the models. Finally, Section IV summarizes the conclusions of this report and indicates avenues of further research.

II. SPECIFICATIONS OF THE MODELS OF EQUIVALENT AVAILABILITY AND HEAT RATE

A. Introduction

Models of equivalent availability and heat rate have been developed for a sample of 171 units (in 57 utilities), which have burned coal for at least three years, were built between 1960 and 1974, and have a capacity of 200 megawatts or more. Consequently, our discussion of the impacts of various factors on unit performance pertain only to large coal units. Although the two models use some of the same factors to explain performance, a specific factor could increase the level of equivalent availability while decreasing heat rate, thereby improving one measure of performance while worsening the other.

The factors affecting equivalent availability and heat rate can be grouped under the following headings:

1. "general" characteristics of the unit;
2. engineering design characteristics of the unit;
3. coal quality;
4. financial characteristics.

We discuss the importance of each of these groups of factors in determining unit performance.

B. General Characteristics of the Unit[3]

The age, vintage and size of units are the characteristics most frequently used to standardize comparisons. However these measures are not satisfactory in explaining differences in unit performance. Actually, they explain very little. Why have the newer units not performed so well? What is it about them that causes them to be less available? The same can be asked of size and age. Age, vintage and size are not operational variables. The principal effect of the general characteristics on unit performance is not attributable to any intrinsic meaning they have. Rather, they reflect the effect of variables missing from the specification of the model.

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[3] For complete discussion of the effect of general characteristics on performance, see S. M. Stoller Corporation, op. cit., pp. 4-1 to 4-9.

All three of these variables exhibit significant time trends which correlate quite strongly with the time trends in performance indices over the same period. Over the sample period, performance declined, unit size increased, age for a specific unit increased and vintage (as measured by commercial operating date) increased. It is not surprising that age, size, and vintage are strongly correlated with performance. However, they may well be proxies for other trend variables which more satisfactorily explain unit performance.

1. The Effect of Age

There is probably a "real" effect of aging on a unit. Many problems which affect a unit during its early years of operation can be corrected in a few years. Therefore, the average performance of a group of units should show some improvement over the few first years of operation. Data on performance indicate that coal units show a tendency for equivalent availabilities to improve several percentage points during years 2-4 and then to decline steadily in subsequent years to levels below those experienced in the first year of operation. It appears likely that this is due to increased outage time caused by boiler problems beginning around the fourth year of operation.

However, age is also a proxy for trends in other variables. First, age may reflect trends in operating and maintaining units or fuel quality variables we have not been able to measure. If such trends cannot be measured with other variables, the age variable in the model captures both its own effect and serves as a proxy for the effect of missing variables. If the effect of the missing variables dominates the "own" effect of age, the regression coefficient estimated for age in the model will more closely reflect the effect of the missing variables rather than age.

2. The Effect of Size

The differences in the apparent effect of size on unit performance results from non-random variations of important design and operating factors over the size range, rather than from any inherent size effect. As with age, size can be a proxy for missing variables in the model. For example, one of the principal effects of size is related to the difference in the performance of supercritical and subcritical units which we discuss below and if this variable is not included in our analysis, size will show a larger coefficient.

3. The Vintage Effect

The vintage effect is comprised of two separate effects: (a) the maturation of existing technologies, and (b) the introduction of new technologies. In the first case, as a technology matures, engineeering problems are resolved and later generations of identical equipment perform better than the first generations. In terms of our sample, it appears most of the units included are first or second rather than later generations. In the second case, new technologies replace existing technologies. Here, the effect on performance is not clear-cut. Assuming that the new technology should perform better than the existing technology, it is not clear whether the first generation of a new technology will outperform older generations of an existing technology. To test these effects separately it would be useful to have one variable measuring the generation within a technology (e.g., the third generation of supercritical boilers should perform better than the first) as well as the technology itself. In many cases, the mean impact of the different technologies (supercritical boilers, etc.) has been included in the model. Our models do not explicitly take into account the age of the technology.

C. Engineering Design and Operational Characteristics of a Steam Generating Unit*

The operation of a steam generating unit is a multistep conversion of one type of energy to another resulting in the production of electricity. This process involves, first, the conversion of potential energy of the fuel, in this case coal, into heat energy by combustion in the furnace of the boiler. Next, this heat energy is transferred to the water and steam in the boiler. The resultant steam is then released from the boiler at high pressures into the turbine where it is converted to mechanical energy. Finally, the mechanical energy rotates a metal rod in an electromagnetic field in the generator thereby converting mechanical energy into electrical energy.

The principal components of the generating unit include:

- Coal Pulverizers
- Boilers and Auxiliary Equipment
- Turbine-Generator

There are various design options for each of these components which can have some effect on the efficiency of the energy conversion. According to engineers, both within various utilities and at Arthur D. Little, Inc., there is a fair amount of controversy as to which design factors affect performance and the extent of their effect. Many times, differing viewpoints depend on the utility's own experiences. We have been able to obtain data for some of these design parameters, but not all of them.

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* Much of this discussion is based on: Shields C., Boilers--Types, Characteristics and Functions, McGraw Hill Book Company; Babcock and Wilcox, Steam--Its Generation and Use, 39th edition; supplemented by discussions with plant managers at VEPCO's fossil-fired stations. Since both books have been written by boiler manufacturers, some discussions presented therein may be somewhat biased toward their respective products.

1. Coal Pulverizers

The coal is pulverized before being burned in the furnace. Moisture in the coal affects the performance of the pulverizers (an effect we were able to test statistically). Deviations from the original specifications in coal quality (grindability and percent ash content) also affect the performance and the required capacity of the pulverizers, an effect we were not able to test given the lack of data on original design coal quality or the pulverizer capacity.

2. Boilers and Auxiliary Equipment

When the coal has been pulverized, it then enters the furnace where the combustion occurs. The furnace is a large open chamber whose walls and ceiling are formed by the boiler waterwalls. As the fuel is combusted, the radiant heat given off by the fireball in the furnace is transferred to the waterwalls. From the furnace, hot gases exit into the convection section of the boiler.

Among the characteristics of furnaces which are believed to yield significantly different results on availability are: (a) whether the furnace has wet or dry ash removal; (b) whether the furnace sizing is adequate in a dry-ash furnace; and (c) whether the boiler is a balanced draft or pressurized boiler.

a. Dry-Ash versus Slag-Tap Furnaces

Dry-ash furnaces are designed to allow ash to cool down to below its ash softening temperature (AST). Most of the dry dusty ash can then travel through the system and be eliminated through the stack. Slag-tap furnaces, on the other hand, are designed to eliminate ash from the system by maintaining temperatures in the furnace that allow ash to remain as liquid slag and be continuously drained toward the furnace bottom. The most successful slag-tap furnace is the cyclone furnace.

The type of furnace built, whether dry-ash or slag-tap, depends upon the characteristics of the coal the unit is expected to burn. Dry-ash furnaces are particularly suited to coals with high AST, but are difficult to utilize with coals having low ASTs because the slag remains too sticky or molten and tends to build up on furnace walls and bottom. The slag-tap furnace has been developed to handle coals with low ASTs such as Midwestern coals. Experience has shown that the required maintenance and cleanup is greater for cyclone than dry-ash furnaces. The increased maintenance in general requires more downtime and lowers availability for these furnaces. We were able to test the effect of cyclone furnaces on performance.

b. Furnace Sizing in Dry-Ash Furnaces

Dry-ash furnaces are usually designed with a sufficient amount of radiant surface so that gas temperatures are reduced to a level where these sections of the boiler can remain clean with the aid of sootblowers. The usual design criterion of furnace size when using this method of cooling gases is the "heat release rate" (HRR), which is defined as the heat available per hour per square foot of waterwall. The HRR, in turn, implies the level of furnace exit gas temperatures (FEGT). The furnace is usually designed with a HRR which will insure FEGTs below the ash softening temperature of the coal which is expected to be burned in the unit. This insures that the molten ash particles will cool to dry dusty ash which can travel easily through the boiler. If the FEGT is above the AST, slagging will occur in the radiant and convection passes of the boiler. The design HRR indicates the range of AST that the coal burned in the unit may have and still avoid slagging problems. It defines the allowable deviations in AST from the design AST, which in turn, should be compared to the AST of the coal actually being burned. We have not tested the effect of slagging on performance since we have only recently acquired data on the design HRR.

c. Balanced Draft or Positive Pressure

A final important design parameter of the furnace is the pressure differential within the boiler. In order for fuel to combust it is necessary to supply a quantity of air to the surface area of the fuel since oxygen is necessary for combustion. This is accomplished by moving the combustion gases away from the surface of the fuel towards the furnace exit, through the boiler and eventually out the stack by means of a draft.

In order for there to be a flow of gases there must be a pressure differential within the boiler. The two types of boiler/furnace design which are used to create the pressure differential are called balanced draft and positive pressure. In a positive pressure boiler, the pressure within the boiler is greater than atmospheric pressure resulting in the desired pressure differential between the boiler and the stack. Severe leakage in the boiler seal causes a significant number of outages in positive pressure boilers. Moreover, leaks in the boiler seal cause fine soot to be blown around, which enters the turbine casing and causes problems.

In a balanced draft boiler, pressure is slightly less than atmospheric pressure: The draft is maintained through simultaneous operation of induced draft fans which take air out of the boiler and forced draft fans which blow air into the boiler. The induced fans increase the initial cost, but reduce the amount of ash leakage out of the boiler thereby keeping the entire plant cleaner than a positive pressure design would. In general, EEI data indicate that balanced draft systems have fewer outages and need less cleanup and maintenance than a positive pressure unit. We were able to test statistically the hypothesis that balanced draft systems work better than positive pressure systems do.

The next section of the boiler consists of a series of connected tubes through which water enters as a liquid, is heated, evaporated to steam, superheated and then leaves as superheated steam. Auxiliary equipment, outside the main boiler, preheats the water entering the boiler (economizer) and the air entering the boiler (air heater), and pumps the water into the boiler (feedwater pump).

The type of energy used to drive the feedwater pump directly affects the gross kilowatt-hours generated by the unit, i.e., the denominator of gross heat rate. A steam- or shaft-driven pump uses some of the energy in the boiler or turbine before it is converted to electricity, while a motor driven pump uses some of the gross kilowatt-hours generated by the unit. For units with either steam- or shaft-driven pumps, gross heat rates will not represent the true amount of power generated by the unit.[5] Therefore, the type of driver used in the feedpump is included as an explanatory factor in the heat rate model.

Boilers can also be classified according to the method of water circulation:

1. Recirculating-Drum Type
    - (a) Natural circulation
    - (b) Controlled circulation
2. Once-Through
    - (a) Subcritical pressure
    - (b) Supercritical pressure

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[5] In general, these types of drivers are more efficient than the electric motors.

The major differences between recirculating boilers and once-through boilers are as follows: In recirculating boilers, the water in the boiler tubes is not evaporated to complete dryness in the tubes but only to the point at which dissolved salts and solids are retained in solution. The mixture of water and steam then passes to a steam and water drum, where the steam is separated and purified. The steam is passed through a separator where excess water is removed, then sent to the superheater. The excess water, along with the feedwater, is then recirculated through the boiler.

In the supercritical boiler, pressure is maintained at or above critical pressure (3,206 psi) in all sections of the boiler. At critical pressure and temperature (705.4° F), steam and water weigh the same and can no longer be separated. In a supercritical unit, feedwater is forced through the different sections of the boiler, with a change of state (from water to steam) taking place in its course along the full length of the boiler tube.

The subcritical once-through boiler, sometimes called a modified once-through boiler, discharges its wet steam and water to an external separating chamber. Some of the water is removed by blowdown to control for impurities in the water, the balance of the water accompanies the steam into the boiler convection section where it is evaporated to complete dryness.

There are a number of reasons why the availability of once-through units tends to be lower than that of recirculating units. First, the boiler tubes of once-through boilers whether subcritical or supercritical require more maintenance than the recirculating boilers. The evaporation process in a once-through boiler is such that the dissolved salts and solids deposit in the tubes, whereas in a recirculating boiler, the steam traveling through the evaporator has been purified. (The problem of impurities in the steam is greatest in the supercritical units where there is no water and steam separating mechanism.) Second, problems of slagging and fouling are more severe in once-through boilers than in recirculating boilers, because furnaces of once-through boilers have historically been less generously sized than furnaces of recirculating boilers. Finally, equipment in supercritical units requires more maintenance since it is subjected to greater wear and tear than in other types of units. In general, units with supercritical boilers are designed to have more efficient heat rates because of the supercritical pressure in the unit.

In terms of performance, we would expect equivalent availability to deteriorate as we move down the list given on page II-8. This can be explained by the increase in the complexity of the equipment, the increase in the impurities of the steam in the boiler tubes and the increase in fouling and slagging. Moreover, supercritical boilers are of more recent vintage than the other boilers and their technology is still being refined and improved.

By contrast, in terms of heat rate, we would expect performance to improve as we move down the list, with supercritical units having the best heat rates of the group, when they are available to run.

Thus, by choosing the type of units with the best heat rate, we also choose the type with the poorest availability, and vice versa.

3. Turbine-Generators

Turbine-generators do not exhibit the variety of design that the other components of the unit do. In fact, reliability of the turbine-generator seems to depend on who manufactured it, rather than on the type of design. It is widely believed that, between the two major producers of turbine-generators, General Electric builds a better machine than Westinghouse. We were able statistically to test the effect of turbine-generator manufacturers.

D. Quality of Coal

The quality of coal is probably one of the most important and least easily defined factors affecting a generating unit's performance. The available data give the chemical composition of the coal but, the percent of ash, sulfur and moisture per ton of coal do not measure completely the characteristics generally believed to affect performance. For example, the percent of ash in the coal is not the sole characteristic of ash influencing the design and successful operation of the boiler. The ash softening temperature, viscosity and grindability are also relevant. Moreover, even when the relevant characteristics of the constituents can be properly measured, absolute statements cannot be made concerning how the quality of the coal affects the unit's performance, since the effect on performance depends upon the degree to which the characteristics of the coal being burned in the unit match those for which the unit was designed. A low ash softening temperature, *per se*, is not a poor characteristic of coal, unless the furnace is a dry-ash rather than slag-tap furnace.

1. Ash

One of the principal problems of ash in the combustion process is slagging. Slagging occurs when the ash in the hot furnace gases remains in a molten state when leaving the furnace. The molten ash adheres to the furnace waterwalls as well as the convection passes, forming a coat of insulation thus preventing heat transfer. Unless a furnace is specifically designed to handle liquid slag, slagging is a serious problem, and could affect both heat rate and availability. In slag-tap furnaces, the viscosity of the ash determines the ease with which the liquid slag can flow at furnace temperature. However we have no measure of these two relevant variables, one relating design AST to current AST, and the other, measuring viscosity.

The heat content of the coal is also affected by the percent of ash present in the coal, i.e., the higher the percent ash the lower the Btu content of the coal. Thus, to generate the same number of kilowatt-hours with a unit would require more tonnage of a higher ash coal. This may affect availability, given limited pulverizer capacity. We were able to test this hypothesis.

2. Sulfur

The bad reputation of sulfur is due to its effect on the boiler when chemically combined with other elements. Under certain conditions, these compounds may corrode boiler components; others contribute to the fouling of gas passages and heating surfaces.

Corrosion of the boiler occurs when flue gases cool below the dew temperature point and water vapor condenses onto the surfaces. This corrosion is accelerated by the presence of sulfur products (SO_2 and SO_3) that form sulfurous and sulfuric acid in the presence of moisture. (To a limited extent the economizer and air heat can be used to adjust flue gas temperature.) On the other hand, a positive effect of high sulfur content is that electrostatic precipitators installed to handle problems of ash emissions appear to work better with high sulfur coal. If this affects the availability of units, it would indicate a positive sulfur/availability relationship. In our model we tested the effects of sulfur content on availability and found the negative effects dominated.

3. Moisture and Grindability

Moisture in coal can affect unit performance in two ways. First, the higher the moisture content of the coal, the greater the difficulty in removing the pulverized coal from the pulverizer. Second, the actual heat content of the coal which can be used to generate electricity is lowered, since a certain amount of the Btus are required to evaporate the moisture. We tried to test the latter effect, using moisture to adjust for Btus, and the former by using percent moisture directly. Only the aggregate effect of both was successfully included in the models.

Grindability is a term used to measure the ease of pulverizing a coal in comparison with a standard coal. Once again, the grindability of the coal is a problem only if its index differs from that for which the pulverizer was designed. However we had no data on grindability or initial design.

In summary, this discussion skims the surface of the types of problems which emerge from coal combustion. There are many more complex chemical reactions among the different compounds as the coal is burned. However, while these reactions would be required for a detailed engineering analysis of combustion in the unit, they are not essential to an econometric model which explains aggregate measures of unit performance.

E. Financial Characteristics

There are a number of ways a utility may upgrade a unit. First, the unit as a whole may be improved by replacing obsolete or defective equipment, such as a turbine. Second, additional equipment can be installed in the unit such as the fans required to convert a positive pressure to a balanced draft boiler. In both cases, the cost of such changes would be included in additions to plant which are considered capital investment. Alternatively, a utility may seek short-run solutions to problems with performance. These could include minor modifications to equipment such as patching up boiler leaks. The cost of such items would be included in plant operation and maintenance expenses. Performance of a unit is, therefore, related to the total amount spent on additions to capital and operation and maintenance (O&M) expenses.

Several factors determine the utility's ability to finance either capital or O&M expenses. The ability of a utility to finance additions to capital is a function of its ability to raise debt and equity. This, in turn, is related to the utility's earned rate of return relative to its existing obligations. Further, the utility's ability to finance O&M expenses is related to its past expectations of financial stability which may be most easily gauged by its recent history of the earned rate of return on equity.

In our analysis, we tested the hypothesis that availability was related to the previous three years' levels of earned return on equity. The earned return however does not in itself say whether the company is in financial trouble: it must be compared with what the company "required". We used changes in the average yield on long-term utility bonds as an indicator of changes in the required return on equity.

We tested the hypothesis that "net earned return" affected availability, in two ways. First we tested on the cross-section time-series data, with all years taken together. Then, since there was a time series in the "net earned return" data (it got worse over time) we tested each year separately. This gave the effect of "net earned return" in the previous years on the performance for each year.

However, there is not a unique relation between ROE and availability because in years when units perform poorly, the utility may find it necessary to increase the amount of power it purchases. In some cases, the additional capacity charges cannot be recovered immediately and must be financed from current earnings. Also, more money should be spent on increased maintenance. The effect of poor availabilities if accompanied by increases in maintenance and purchased power could be to lower earned rate of return on equity. Summarizing, in the first case we tested the hypothesis is that historically low earned rate of return on equity causes subsequent performance to deteriorate. In the alternative hypothesis, poor performance directly affects current earned return on equity.

To test the alternative hypothesis, we ran annual regressions relating equivalent availability to current rate of return. The coefficients on rate of return were insignificantly different from zero. The hypothesis that rate of return is determined by the current year's availability was not supported. The lagged rate of return by contrast showed a strong relation with equivalent availability; the hypothesis that rate of return affects subsequent availability is much more likely than the alternative causal hypothesis.

III. RESULTS OF THE MODELS OF EQUIVALENT AVAILABILITY AND HEAT RATE

In this section, we review the results of the equivalent availability and heat rate models. While a complete review of the data and data sources is presented in Appendix A, we briefly review the definitions of some key variables and criteria used for sample selection and then turn to the regression results.

The two dependent variables in the models, i.e., the performance measures we are explaining, are gross annual unit equivalent availability and gross annual heat rate. Gross is defined as the kilowatts (or kilowatt-hours) which the unit is capable of producing (or has produced) including the amount of capacity (or generation) needed to run the equipment, lighting and space conditioning in the unit. Net measures would exclude capacity and generation used within the unit. Data on equivalent availability and heat rate were available only on a gross basis from the National Electric Reliability Council (NERC) and Federal Energy Regulatory Commission (FERC). In any event, since this study is designed to measure the overall mechanical efficiency of the unit, gross is the more appropriate measure.

The data base used to estimate the models is comprised of a sample of 171 generating units in over 100 plants which burned coal in at least 3 years, were built between 1960 and 1974, and are over 200 megawatts. The number of utilities covered by the sample is 57. The sample period is 1969 to 1977. For units built after 1969, the sample period covers their commercial operating date (COD) to 1977. Data in COD years are excluded from the model. Missing unit-years in the data base are due to either missing NERC or FERC data in those years.[6]

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[6] The data base used in the heat rate model has fewer observations than that used in the equivalent availability model, since the heat rate variable was constructed using boiler specific fuel consumption data from FPC Form 67s for which many unit-years were randomly missing.

Two standard statistical measures are presented with the regression results of the models: (1) the t-statistic for the regression coefficients which indicates whether the estimated coefficient is statistically significantly different from zero. With few exceptions, the t-statistics of included variables are greater than 2.0, indicating the coefficients are significantly different from zero at a 95 percent confidence level; and (2) the R^2 for the regression, which measures the "goodness of fit" for the regression as a whole. Roughly defined, R^2 measures the percent of sample variation explained by the regression (as measured by the ratio of the variation explained by the regression to total sample variation).

Two caveats should be noted in determining whether an R^2 is good or not. First, the researcher has some a priori notion of whether an R^2 is good or not relative to the type of data being used in estimating the model. For example, if a model is being estimated using time-series data where both dependent and independent variables exhibit strong trends or comparable cycles over the sample period, a good R^2 should fall between 90 and 100 percent. On the other hand, if a regression is based on a pooled cross-section time-series data base, we would expect a much lower R^2. The introduction of cross sections greatly reduces the correlation of trends of the individual time series for each cross-section over the entire data base. Moreover, as the number of observations increases relative to the number of independent variables, there may be an increase in sample variation (denominator of R^2) without a corresponding increase in explained variation (numerator of R^2). This serves to further lower the R^2.

Second, in addition to the fact that the data bases used in our models were very large pooled observations, there are a number of other reasons why we would expect low R^2s in these models due to a large sample variation. First, part of the sample variation for equivalent availability is due to measurement and reporting errors in the NERC/EEI data series. About 30 percent of the variance of the equivalent availability data measured with error is due to these errors. The effect of this reporting error is to decrease the R^2 roughly the same amount, to reduce the t-statistics, and to increase the standard error of estimate. These errors are random and cannot be explained by a regression. Wide random fluctuations in performance due to accidents or catastrophies, while adding to sample variation, cannot be explained in any systematic fashion by unit design and operation variables. Hence, given the type of data, with the inherent reporting variability, pooled cross-section time-series observations, and a large number of observations, R^2s should not be expected to be above 40 percent and 20 percent would not be unusual.

There are things which can be done to increase the R^2. We view some of these things as pointless tricks, if they add nothing to our knowledge but only add points to the R^2s. For instance, in the limit, if the number of explanatory variables approaches the number of observations, very high R^2s will be observed. Another method of increasing R^2 is to reduce sample variation by using a smoothing technique on the data, such as averaging. The effect of using average data on estimating in the same model is to usually increase the R^2 of the model.[7] An approach we did use to increase the R^2 was to correct for reporting errors to the extent we could. This reduced the reporting error in the data to roughly 10 percent of the variance.

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[7] Johnston, J., Econometric Methods, New York: McGraw-Hill Book Company, 2nd edition, 1972, p. 230.

We now turn to a discussion of the regression results of the equivalent availability and heat rate models, respectively. In order to help the reader distinguish the various models, here is a summary table specifying the variables and the form used in each model discussed below.

Name	Dependent Variable (1)	Form (2)	Independent Variables (3)
Comparison Group	E.A.	Straight	Size, Age, Vintage
Comparison Group (logit)	E.A.	Logit	Size, Age, Vintage
Model I	E.A.	Straight	Same As Comparison Group plus Engineering Variables and Coal Quality
Model I (logit)	E.A.	Logit	
Model II	E.A.	Straight	Same As Model I plus Financial Characteristics
Model II (logit)	E.A.	Logit	
Heat Rate	Gross H.R.	Straight	See Text.

A. Equivalent Availability Model

Three models were estimated to explain equivalent availability. The first model was set up to parallel the comparison group analyses. While specific comparison groups were not set up, the unit characteristics used as criteria to develop comparison groups were used as explanatory variables in the regression. The other models contain an expanded set of regressors as discussed earlier. They differ from each other in their explanation of the strong time trend exhibited by the equivalent availability data. The first of these posits the trend is comprised of two components: age and vintage. The second posits the trend is due to the eroding financial position of the utilities over the sample period.

1. The Form of the Model

Before discussing and comparing the results of these two models, a brief explanation of dependent variable specification is needed. For each model, two regression specifications are presented. The first specifies equivalent availability as the dependent variable; the second specifies the logit transformation of equivalent availability.[8]

The logit is the theoretically correct statistical specification of dependent variables which have upper and lower bounds on the possible values they can assume. In the case of equivalent availability, the upper bound is 100 percent and the lower bound is zero percent. By using the logit transformation of equivalent availability, the predicted value of the dependent variable and the confidence intervals around that value will never fall outside the 0-100 range. This is not the case for the regression where equivalent availability untransformed is the dependent variable. Nonetheless, in addition to the results of the logit model we present the results of the model with equivalent availability as the dependent variable, because the regression coefficients are more easily interpreted in this model and, in general, the signs of the coefficients and the predictions from the two regression specifications do not differ significantly.

For ease of discussion, the impacts of the different variables are discussed in the context of the regression coefficients estimated by the equivalent availability model. The regression coefficients in the equivalent availability specification can be interpreted as the number of percentage points that the equivalent availability increases or decreases in response to a unit change in the relevant independent variable. For certain characteristics, the independent variable assumes a value of zero or one, depending on whether or not the unit has that type of design characteristic. For example, if a unit has a cyclone furnace, the cyclone furnace variable equals one; if not the variable equals zero. For the 0,1 type variables, the regression coefficient simply indicates the increase or decrease (in percentage points) in equivalent availability for a unit having that specific design characteristic.

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[8] The logit transformation of equivalent availability is defined as $ln\ [EA/(100-EA)]$ where EA is equivalent availability.

2. Results of "Comparison Group" Model

In Table 2, we present the regression results for the model which relates equivalent availability to a few general unit characteristics, namely, vintage, age and size (hereinafter referred to as "Comparison Model"). In Tables 3 and 4, we present the regression results for the fully specified models, hereinafter referred to as Models I and II respectively. In addition to the general unit characteristics, we have included variables on boiler design and manufacturer, turbine-generator manufacturer, coal characteristics and financial characteristics. Comparing the results of the Comparison Model with Model I, the coefficients for age and vintage are remarkably similar. Size is the one variable for which the coefficient differs. The reason for the difference is that some of what appears to be the size effect is really the effect of once-through boilers, a variable which has been explicitly included in Model I. Comparing the explanatory power of the two models (as measured by the R^2), Model I is a much better vehicle for explaining equivalent availability than the Comparison Model. Furthermore, the coefficients of the engineering design variables are all highly significant with strong t-values. The difference in the two models demonstrates the superiority of the fully specified econometric model over a comparison group analysis.

3. Results of Model I

The more interesting aspects of Model I are the interpretation of the results for the design and operating characteristics.

a. Furnace Design Variable

As expected dry-ash furnaces had higher availabilities than cyclone (slag-tap) furnaces. On average, equivalent availability of cyclone furnaces was 4.5 percentage points lower than that of dry-ash furnaces.

As expected balanced draft furnaces performed better than positive pressure furnaces. If the unit was built with a balanced draft furnace, its availability was 4.6 percentage points higher than a positive pressure unit. Given the demonstrably better performance by balanced draft units, a number of units have converted from positive pressure to balance draft furnaces. In order to incorporate the conversion effect in the model, two variables were specified. The first variable measured the effect on equivalent availability of actually converting the unit. It equaled one in the year of conversion and zero in all other years. As expected the coefficient of this variable was negative implying that some downtime was required to convert the unit. The second variable was included to capture the change in performance in the years after the conversion. The coefficient on this variable was negative, but not significantly different from zero; however, our data only extend through 1977, and include only a few years after the conversions, many of which took place between 1974-1977.

b. Boiler and Turbine-Generator Variables

The only types of boiler circulation included in these regressions were once-through versus recirculating. While data for the sample units were available for a more disaggregate breakdown (presented in Table 1), the number of sample units in a disaggregate class was too small to reliably draw inferences from.

However, there were sufficient data to model the most important class of circulation namely, once-through versus recirculating boilers. As expected, the availability of once-through units is less (by roughly 6 percentage points) than that of recirculating units. The reasons for this were detailed in Part II, Section B.

Finally, both boiler and turbine-generator manufacturers were included in the model. As expected, the availability of General Electric turbine-generators was better than that of Westinghouse (by roughly 2 percentage points). The differences in performance among the different brands of boilers cannot be assumed to be due solely to quality differences among the boilers but also to differences in the types of boilers and furnaces manufactured by them. For example, only Combustion Engineering manufactures tangential dry-ash furnaces.[9] Also, in our sample, all controlled recirculating units are manufactured by Combustion Engineering. Therefore, the Combustion Engineering coefficient may reflect either the quality of Combustion Engineering boilers or the fact that a large portion of them are tangential furnaces and controlled recirculating boilers.

c. Coal Characteristics

As a group, the variables on coal characteristics are the least satisfactory among the groups of variables included in the model. In particular, data on the characteristics of the coal the unit was designed to burn were unavailable.[10] Moreover, no information was available on ash softening temperature or coal grindability.

The coal characteristics included in the model were the chemical composition of the coal actually burned in the unit in a particular year. While these measures are descriptive for sulfur, moisture and heat content of the coal, the ash content of the coal does not describe the slagging potential of the coal, which is the chief problem caused by ash. Sulfur content can reduce unit performance because of corrosion, slagging and fouling in the boiler. The model indicates that for each percent increase in sulfur content, availability is reduced by 0.5 percentage points. Similarly, for reasons mentioned earlier, moisture adversely affects performance: a 0.1 percentage point reduction in performance for each percent increase in moisture. The heat content of the coal has a positive effect on availability. The regression coefficient of percent ash is not significantly different from zero. As noted, this is not the sole characteristic of ash affecting availability.

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[9] Tangential furnaces refers to a type of firing design in which the burners are in opposing corners of the furnace.

[10] See Part IV for future research to be done in this area.

d. General Characteristics

As noted previously, theoretically the effect of age should be to lower availability in the first year of operation, raise availability in the second to fourth year of operation, and then decrease availability in the following years. Unfortunately, this age specification does not perform as well in the model as the age variable which is currently included in the model, which implies that unit performance decreases by 1.3 percentage points per year. To the extent age is capturing trend effects of missing variables, the trends of these variables dominate the specific age effects.

The size coefficient indicates that larger size brings reduced performance in the range from 200-480 megawatts. Above this size, the effect of size appears to have negligible impact on performance. The size effect may be capturing the effects of the increased complexity of the equipment and consequent maintenance, as unit size increases. Finally, the vintage coefficient indicates units of more recent vintage do not perform as well as older vintage units. This may reflect the possibility that newer units are first generations of new technologies, such as supercritical units. We are testing other specifications of the vintage effect to take into account trends in design parameters such as heat release rates.

4. Results of Model II

Model II for equivalent availability includes the variables in Model I and also, the earned rate of return on equity (ROE). The ROE is defined as the earned rate of return on equity less the yield on newly issued long-term utility bonds. The relevant ROE variable in any year is the three-year moving average for the three years prior. The ROE was tested as a separate cross-sectional effect for each year from 1970-1977, i.e., abstracting from its time-trend.

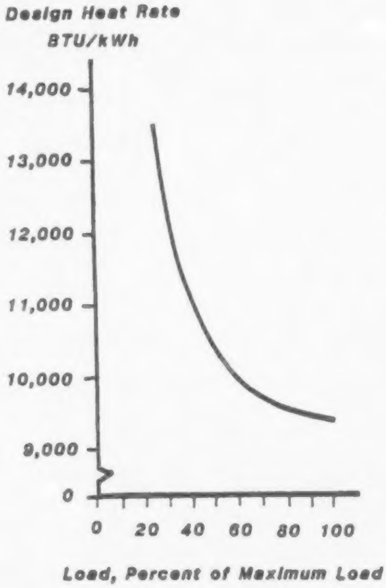
In general, the coefficients of the unit design characteristics are similar in the two models (for those coefficients which are statistically significant). The major difference between the two models is in the coefficients of the age, vintage and fuel characteristics. As expected the inclusion of the ROE variable reduces the age and vintage effects since ROE is a strong trend variable over our sample period. Also, the inclusion of the ROE had an effect on the coefficients of the fuel characteristic variables increasing their absolute values and their statistical significance. These were the only other variables included in the model which changed over time.

The coefficient of ROE was stronger during the 1975-1977 period than in the 1971-1974 period. The coefficients averaged 1.79 in the period 1971-1974 and averaged 2.20 in the period 1975-1977. The change in the coefficients over the two time periods parallels the change in the riskiness of utility stock and fuel market conditions between the two periods. The coefficient of this variable suggests there is an association between high ROE and subsequent availability. These coefficients were highly significant. As noted earlier, the causality between availability and ROE may run both ways. We are reviewing alternate methods of checking the direction of causality.

B. Heat Rate Model

1. Unit Design Heat Rates

Unit design heat rate curves are determined by the laws of physics describing the change from heat energy to work energy. Design heat rate curves relate unit heat rate to unit output and can be approximated by a hyperbolic function. Specifically, unit heat rate is inversely related to unit output. Graphically, the curve is represented as:



The approximation of the unit heat rate curve can be written as:

$$HR_i = a_i + \frac{b_i}{x_i}$$

Where HR_i = heat rate of unit i
x_i = output of unit i (Can be expressed relative to the maximum capability of the unit.)
a_i = upward displacement parameters for unit i
b_i = curvature parameter for unit i

The values of the parameters of the heat rate curve depend on the engineering design of the unit. For purposes of our model, we have assumed that b_i is constant across units regardless of design.[11] The displacement parameter, a_i, is assumed to vary across units due to differences in engineering design and is assumed to vary for an individual unit over time due to aging of the unit. The above assumptions concerning the coefficients of the heat rate curve lead to the following model specification.

We hypothesized that the placement of the curve (the value of a_i) depends on various engineering design characteristics and unit age. As noted above, we assumed b_i=b for all units in our sample.

The regression results for the heat rate model are shown on Table 5. Before turning to a discussion of these results, a note on the construction of the dependent variable is warranted. There are no published data, either gross or net, on industry-wide unit heat rates. There are some data for units with low, more efficient heat rates. To use a sample of only the most efficient units to estimate the heat rate model would yield biased and unrepresentative results. Consequently, we derived gross annual heat rates for the units in our sample by combining relevant data series from a number of published sources.

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[11] We have tested this hypothesis using design heat rate curves on all fossil-fired units in VEPCO's service area.

2. Regression Results

a. Feedwater Pump Drivers

Turning to the regression results, on Table 5, one of the most important variables affecting gross heat rates is the type of energy used to drive the feedwater pumps: electricity, shaft, steam or other. If the feedwater pump is shaft- or steam-driven, then energy is drained from the unit to run the pump before this energy has been converted to electricity. Heat rates computed for these units would be higher (less efficient). A variable defining the type of fuel used to drive the feedwater pump was explicitly included as an independent variable to take account of this problem. As the regression results indicate, shaft- and steam-driven units have higher heat rates than motor-driven units (by 150 and 193 Btu per kilowatt-hour, respectively). It is not clear what types of fuel drive the feedwater pumps for units in the "other" category. Nonetheless, this category was included separately so the other feedwater fuels would not capture its effect.

b. Boiler and Furnace Design Variables

The boiler design variables included in the model are supercritical boilers and cyclone furnaces. Both these variables reflect major technological designs which would shift the unit design heat rate curve. As expected, supercritical units shift the heat rate curve down. Given the efficiency design of supercritical units, these units tend to have lower heat rate curves than other types of units. The negative coefficient for this variable indicates that their heat rate curves are below those of subcritical units. Cyclone furnaces appear to shift the curve up.

c. Fuel Characteristics

The fuel characteristics included in the model are the primary fuel burned in the unit and the chemical composition of the coal if coal is the primary fuel.[12] (This is a coal unit model, but the selection criterion for units in the sample required that the unit burned coal for at least three years. Consequently, some units in the sample converted from coal to oil or, as in the case of VEPCO, they were converted from coal to oil and then back to coal again.) In the heat rate model, the heat rate curve of units which had converted to oil was found to be higher (less efficient) than that of those burning coal. (Note: The effect of converting from coal to oil was not apparent when tested in the equivalent availability model.) The effect on availability of reconverting back to coal again could not be measured because within the sample period, only two units (Chesterfield 5 and 6) had done so.

The second set of fuel characteristic variables included in the heat rate model relates to the chemical composition of the coal (when coal is the primary fuel). Specifically, the ash and moisture content of the coal burned were included as independent variables.

Both ash and moisture increase the heat rate. Greater levels of ash may be correlated with more slagging which reduces heat transfer. (However we would have expected a similar result in the equivalent availability model as well.) Also higher levels of ash may constrain pulverizer capacity, thereby forcing the unit to run at less than original capacity. Greater moisture levels imply lower actual Btus available to produce electricity since some Btus are consumed in evaporating the moisture from the coal.

d. General Characteristics

Finally, some general unit characteristics were included in the model. As in the equivalent availability model, age and vintage were included. The effect of size on heat rate was tested and found not significantly different from zero. In the case of heat rate, the main size effect appears to have been captured by the supercritical variable. The effect of both age and vintage on heat rate is positive. The effect of age on heat rate is to increase heat rate by roughly 50 Btus per kilowatt-hour a year. The interpretation of the role of vintage on heat rate is linked to the generations of the technologies of the sample units. The age effect, however, appears to be an accurate measure of the strong trend exhibited by the data. Whether age or some other trend variable(s) would be more appropriate is still being investigated.

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[12] A fuel is considered a primary fuel if it accounts for greater than 30 percent of the total fuel burned in the unit.

As a further check on the age effect, we used the age coefficient to predict the declining trend in heat rates, for a sample of the most efficient coal units as reported annually by FERC. The total trend effect over the seven years for which we did the analysis (1970-1977) was roughly an increase in heat rate of 350 Btu per kilowatt-hour, ceteris paribus. When this amount was added to 1970 heat rates to predict 1977 heat rates, the actual 1977 heat rates closely corresponded to the predicted ones.

As in the equivalent availability model, age and vintage may well be capturing effects of strong trend variables. However, unlike the equivalent availability model, the heat rate model is more complex in concept. That is, heat rate curves are based on the original design of the unit. It is not clear what trend variables would cause it to shift out over time.

e. Output Factor

As noted earlier the single most important variable affecting an individual unit's heat rate is output factor. The reciprocal of output factor was included as an independent variable in the model. The coefficient for this variable was assumed to be constant regardless of unit design. Since we had unit design curves for 1980 for all VEPCO's fossil units, we used these data to test the hypothesis that b_i was constant. Most of the heat rate curves have b values between 80,000 and 160,000. (The exceptions are Chesterfield 4 and 6, Yorktown 3 and Possum Point 5 (VEPCO's two very large oil units) which have extremely low coefficients compared to the other units in the system.)[13]

C. Standards of Performance—Using the Results of the Models of Equivalent Availability and Heat Rate

The final product of this study is the development of performance standards for equivalent availability and heat rates against which a specific unit's performance could be evaluated. The purpose of estimating heat rate and equivalent availability models was to provide a tool with which to do this. By specifying the values of the independent variables for a specific generating unit, the model can be used to predict the expected value or "average" of the performance standard of interest. For example, using Model I for predicting equivalent availability, a unit:

(1) built in 1970;
(2) age equal to four years;
(3) with a 600 megawatt capacity;
(4) with a balanced draft boiler;
(5) with a Babcock & Wilcox boiler;
(6) with a Westinghouse turbine-generator; and
(7) using coal with
  (a) 12,000 Btu per pound;
  (b) 3 percent sulfur;
  (c) 10 percent ash; and
  (d) 8 percent moisture

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[13] Future research would be directed to further substantiating the assumption that this coefficient is constant.

would have an annual equivalent availability of 75.6 percent.[14] While the predicted value of the regression is the most likely value given both the statistical error of the model and the fact that all possible explanatory factors affecting unit performance can never be included in such models, the actual value may not equal the most likely value predicted by the model. Moreover, the equivalent availability data are subject to a significant amount of measurement and reporting error. Consequently the researcher is interested in a range of likely predicted values. Specifically, he is interested in the range of values within which he can assert with a specific degree of confidence that the true value of performance falls. The greater the degree of certainty desired, the wider the range of values. Obviously, the types and magnitudes of the policy questions to be answered using the model predictions determine the degree of confidence desirable. A conservative range of values would be a range of plus or minus one standard deviation around the model prediction. Since it is assumed that the error in the regression is distributed normally, there is a 68 percent certainty that the true value lies between plus or minus one standard deviation around the prediction.

It should be noted that while the econometric model approach allows a range around its average, the comparison group analysis, which is based on fewer variables and data points, seldom relies on any statistic other than the group mean.

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[14] Equivalent Availability = 146.38 - 1.23 (70) - 1.36(4) + 2918.65(1/600) + 4.564 + 5.7 + 3.4 + 0.0003(12,000) - 0.54(3.0) + 0.04(10.0) - 0.14(8.0) = 75.59.

IV. CONCLUSIONS

To date most of the statistical studies have been used to determine performance standards--whether engineering or comparison group analyses. Econometric models can also be used for the same purpose, but any statistical comparison should be used with caution. The econometric models described in this report take into account many factors for which nationwide data are available, and these factors can be seen to have a significant effect on performance. To that extent, this study parallels and expands engineering studies. It shows, we believe for the first time, the impact on equivalent availability and heat rate of fuel quality, engineering design and financial factors as well as the variables included in the comparison group analyses. In that sense, this study represents a considerable improvement over comparison group analyses.

There are however other factors affecting performance for which data are not available. Were these to be taken into account also, the values predicted for individual units might well change significantly. Among the variables we believe to be significant, but which we have had to omit are: conversion to coal, boiler sizing, original fuel quality, excess fuel costs and ash softening temperature. The relatively large residuals in our analysis are partly due to large random variations in annual data, and partly due to management.

There is a temptation to attribute all unexplained variance to management, particularly when statistical analysis is used to set standards of performance. This is clearly not the case. A large part of the annual variation is random, and a large part of the unexplained variation beyond that is due to omitted variables. The present study goes a long way beyond the previous work in explaining the variation in performance: future researchers may be able to refine our results.

As with any analysis there are always areas which should be improved, but only some that can be. In terms of the models developed in this report these areas have been identified: (1) Ideally, the fuel characteristics should be expanded to include such characteristics as ash softening temperatures. But, it is doubtful that these data will be available. However, the fuel design parameters may be approximated using characteristics of the fuel that was burned in the early years of operation. We are investigating this approach. (2) In the heat rate model we are continuing our efforts to relate the curvature of the heat rate curve to design characteristics. (3) Variables which measure capital costs versus operating costs of the unit are being considered to evaluate the trade-off between performance, capital costs and running costs. (4) For both the equivalent availability and heat rate models, we are investigating the reason(s) for the strong declining trends in the data over the sample period. (5) In addition to refining these models for coal units, similar models are being developed and will be estimated for oil units.

TABLE 1
Page 1 of 2

SPECIFICATION OF THE MODEL

I. GENERAL CHARACTERISTICS

Ideal Set	Actual Set
1. Age	1. Age
2. Size	2. Size
3. Vintage	3. Vintage
a) Technology Changes (see -ENGINEERING DESIGN PARAMETERS).	
b) Maturation of a Technology	
4. Variability of Load	4. Output Factor

II. ENGINEERING DESIGN PARAMETERS

A) Pulverizers

Ideal Set	Actual Set
1. Pulverizer Capacity	1. Percent Moisture of Coal Actually Burned
2. Type of Coal that Pulverizer Designed For:	
a) Grindability	
b) Percent Moisture	

B) Boilers and Auxiliary Equipment

Ideal Set	Actual Set
1. Design Heat Release Rate of Unit	1. Dry-Ash or Slag-Tap Furnace
2. Dry-Ash or Slag-Tap Furnace	2. Balanced Draft or Positive Pressure Furnace
3. Balanced Draft or Positive Pressure Furnace	3. Type of Circulation
4. Type of Circulation	a) Recirculating
a) Recirculating	i) Natural
i) Natural	ii) Controlled
ii) Controlled	b) Once-Through
b) Once-Through	i) Subcritical
i) Subcritical	ii) Supercritical
ii) Supercritical	4. Boiler Manufacturer
5. Boiler Manufacturer	5. Feedwater Pump by Fuel Type
6. Feedwater Pump by Fuel Type	

C) Turbine-Generators

Ideal Set	Actual Set
1. Turbine-Generator Manufacturer	1. Turbine-Generator Manufacturer

TABLE 1
Page 2 of 2

SPECIFICATION OF THE MODEL

III. COAL QUALITY

Ideal Set	Actual Set
1. Ash	1. Ash
a) Ash Softening Temperature--Design vs. Actual	a) Percent Ash in Coal Actually Burned
b) Viscosity of Coal-Ash Slag	
2. Sulfur	2. Sulfur
a) Percent Sulfur in Coal	a) Percent Sulfur in Coal
b) Flue Exit Gas Temperature vs. Dewpoint	
3. Moisture (see Pulverizers)	3. Btu Content
4. Grindability (see Pulverizers)	
5. Btu Content	

IV. FINANCIAL CHARACTERISTICS

Ideal Set	Actual Set
1. Total Operation and Maintenance Expenditures	1. Earned Rate of Return on Equity (deflated by return on utility bonds)
2. Additions to Capital	
3. Allowed and Earned Rate of Return on Equity	

TABLE 2

COMPARISON MODEL
REGRESSION RESULTS RELATING EQUIVALENT AVAILABILITY OF COAL UNITS TO GENERAL UNIT CHARACTERISTICS

	Dependent Variable			
	Equivalent Availability		Logit of Equivalent Availability[1]	
Independent Variable	Coefficient (1)	t-Statistic (2)	Coefficient (3)	t-Statistic (4)
General Characteristics				
Vintage	-1.23	-6.11	-0.06	-5.46
Age	-1.36	-7.62	-0.08	-7.40
Size[2]	4871.25	10.27	322.85	11.93
Constant	149.18		4.87	
Number of Observations	1,201		1,201	
$\bar{R}^2$	0.16		0.18	
Standard Error of Estimate	14.37		0.82	

[1] The logit transformation of equivalent availability is ln [EA/(100-EA)] where EA is equivalent availability.

[2] "Size" is expressed as the reciprocal of nameplate capacity.

TABLE 3

MODEL I
REGRESSION RESULTS RELATING EQUIVALENT AVAILABILITY OF COAL UNITS TO VARIOUS UNIT AND FUEL CHARACTERISTICS

Independent Variable	Dependent Variable			
	Equivalent Availability		Logit of Equivalent Availability[1]	
	Coefficient (1)	t-Statistic (2)	Coefficient (3)	t-Statistic (4)
General Characteristics				
Vintage	-1.23	-6.15	-0.06	-5.46
Age	-1.36	-7.80	-0.08	-7.67
Size[2]	2918.65	5.17	210.58	6.53
Boiler Design				
BD1[3]	4.56	4.75	0.30	5.51
BD2[4]	-1.43	-0.76	-0.04	-0.34
BD3[5]	-7.86	-2.61	-0.39	-2.29
Cyclone	-4.48	-2.74	-0.27	-2.91
Once-Through[6]	-5.86	-4.74	-0.33	-4.71
Boiler Manufacturers				
Babcock & Wilcox	5.17	3.86	0.37	4.82
Combustion Engineering	4.06	3.38	0.22	3.22
Turbine-Generator Manufacturers				
General Electric	5.64	2.64	0.24	2.01
Westinghouse	3.44	1.59	0.15	1.25
Fuel Characteristics				
MBtu Content	0.30	1.84	0.02	2.17
Sulfur Content	-53.69	-1.09	-4.18	-1.49
Ash Content	4.44	0.38	0.30	0.45
Moisture Content	-13.75	-1.64	-0.88	-1.84
Constant	146.38		4.70	
Number of Observations	1,201		1,201	
$\bar{R}^2$	0.24		0.26	
Standard Error of Estimate	13.73		0.78	

[1] The logit transformation of equivalent availability is Ln [EA/(100-EA)] where EA is equivalent availability.

[2] "Size" is expressed as the reciprocal of nameplate capacity.

[3] "BD1" is equal to 1 if unit is balanced draft, otherwise it is equal to 0.

[4] "BD2" is equal to 1 in the years following conversion from positive pressure to balanced draft.

[5] "BD3" is equal to 1 in year of conversion from positive pressure to balanced draft.

[6] "Once-Through" consists of subcritical once-through and supercritical.

TABLE 4
Page 1 of 2

MODEL II
REGRESSION RESULTS RELATING EQUIVALENT AVAILABILITY OF COAL UNITS TO VARIOUS UNIT, FUEL, AND FINANCIAL CHARACTERISTICS

	Dependent Variable			
	Equivalent Availability		Logit of Equivalent Availability[1]	
Independent Variable	Coefficient (1)	t-Statistic (2)	Coefficient (3)	t-Statistic (4)
General Characteristics				
Vintage	-0.61	-1.16	-0.02	-0.60
Age	-0.79	-1.56	-0.04	-1.34
Size[2]	2323.58	3.47	190.95	5.06
Boiler Design				
BD1[3]	5.82	5.22	0.36	5.81
BD2[4]	0.23	0.11	0.06	0.51
BD3[5]	-10.31	-3.06	-0.49	-2.59
Cyclone	-3.85	-1.99	-0.25	-2.27
Once-Through[6]	-5.68	-4.02	-0.30	-3.82
Boiler Manufacturers				
Babcock & Wilcox	4.50	2.92	0.32	3.64
Combustion Engineering	4.73	3.46	0.25	3.31
Turbine-Generator Manufacturers				
General Electric	3.98	1.59	0.13	0.92
Westinghouse	2.13	0.84	0.06	0.44
Fuel Characteristics				
MBtu Content	0.58	2.72	0.04	3.04
Sulfur Content	-156.74	-2.58	-9.10	-2.67
Ash Content	-0.68	-0.04	-0.25	-0.33
Moisture Content	-35.25	-3.58	-2.14	-3.86
Financial Characteristics				
Earned Rate of Return on Equity:[7]				
1971	1.69	3.33	0.10	3.51
1972	1.46	2.96	0.09	3.09
1973	2.32	5.21	0.13	5.09
1974	1.69	4.38	0.11	4.97
1975	2.00	4.52	0.12	4.69
1976	2.43	4.17	0.12	3.78
1977	2.21	2.49	0.14	2.74

TABLE 4
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MODEL II
REGRESSION RESULTS RELATING EQUIVALENT AVAILABILITY OF COAL UNITS TO VARIOUS UNIT, FUEL, AND FINANCIAL CHARACTERISTICS

	Dependent Variable			
	Equivalent Availability		Logit of Equivalent Availability[1]	
Independent Variable	Coefficient (1)	t-Statistic (2)	Coefficient (3)	t-Statistic (4)
Constant	98.07		1.29	
Number of Observations	958		958	
$\bar{R}^2$	0.22		0.24	
Standard Error of Estimate	14.08		0.79	

[1] The logit transformation of equivalent availability is ln [EA/(100-EA)] where EA is equivalent availability.
[2] "Size" is expressed as the reciprocal of nameplate capacity.
[3] "BD1" is equal to 1 if unit is balanced draft, otherwise it is equal to 0.
[4] "BD2" is equal to 1 in the years following conversion from positive pressure to balanced draft.
[5] "BD3" is equal to 1 in year of conversion from positive pressure to balanced draft.
[6] "Once-Through" consists of subcritical once-through and supercritical.
[7] Three-year moving average, lagged one year, deflated by a three-year moving average of return on new issue long-term utility bonds.

TABLE 5

REGRESSION RESULTS RELATING GROSS HEAT RATE OF COAL UNITS TO VARIOUS UNIT AND FUEL CHARACTERISTICS

Independent Variable	Dependent Variable Heat Rate Coefficient (1)	t-Statistic (2)
General Characteristics		
Vintage	67.70	8.64
Age	48.84	6.74
Reciprocal of Output Factor [1]	115,176.40	11.55
Boiler Design		
Cyclone	184.85	3.48
Supercritical	-119.53	-2.80
Source of Energy for Feedwater Pumps		
Shaft	149.64	2.54
Steam	192.74	3.73
Other	77.09	1.16
Fuel Type [2]		
Oil	315.63	2.92
Fuel Characteristics for Coal		
Percent Ash	11.07	1.95
Percent Moisture	13.26	3.27
Constant	2,657.91	
Number of Observations	905	
$\bar{R}^2$	0.31	
Standard Error of Estimate	497.32	

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[1] Output Factor is equal to ([Capacity Factor/(Service Hours/Period Hours)].

[2] Some of the sample units burned oil for a few years.

APPENDIX A

SOURCES OF DATA

I. VARIABLES: UTILITY NUMBER, UTILITY NAME, UNIT NUMBER, UNIT NAME, YEAR OF RECORD, COMMERCIAL OPERATION DATE, NAMEPLATE RATING, MAXIMUM DEPENDABLE CAPABILITY, PERIOD HOURS, SERVICE HOURS, AVAILABILITY FACTOR, CAPACITY FACTOR, AND EQUIVALENT AVAILABILITY FACTOR

Source:

1969-1975 Period: Performance Data supplied by Edison Electric Institute/Federal Energy Administration in the form of a computer tape, as of 1975.

1976-1977 Period: Performance Data supplied by the National Electric Reliability Council (NERC) in hard copy form, as of 1977. Note the responsibility for the data was shifted from EEI to NERC.

Exceptions:

For the following units and years, the equivalent availability was supplied during telephone conversations with the corresponding utility.

Utility	Unit Name	Year
Central Illinois Light Company	E. D. Edwards #3	1975
Commonwealth Edison Company	Kincaid #1	1977
Public Service Company of New Hampshire	Merrimack #2	1977
Tampa Electric Company	Gannon #6	1975
Union Electric Company	Labadie #1	1977
West Pennsylvania Power	Hatfield #1	1977

II. VARIABLE: OUTPUT FACTOR
DERIVATION: CAPACITY FACTOR/(SERVICE HOURS/PERIOD HOURS).

III. VARIABLES: HEAT RATE, FUEL CHARACTERISTICS AND CONSUMPTION
Heat Rate was Calculated Using The Following Formula:

[(Btu content of coal x 2000 x Amount of coal burned)

+ (Btu content of oil x 42 x Amount of oil burned)

+ (Btu content of gas x 1000 x Amount of gas burned)] /

(Capacity factor x Maximum dependable capability x Period hours).

Fuel Consumption:

Source:

1969-1977

Period: Federal Power Commission Form 67, Steam-Electric Plant Air and Water Quality Control Data, Annual Report.

Fuel Characteristics:

Source:

All plants in sample for the period 1969-1972: Federal Power Commission Form 67, Steam-Electric Plant Air and Water Quality Control Data, Annual Report.

All plants in sample, excluding the seven listed below, for the period 1973-1977: Federal Power Commission, Form 423, Report of Cost and Quality of Fuels for Electric Plants, as received on computer tape.

Exceptions:

The Form 423 data for the period 1973-1977 were not available for the following units. The source of this data is: Federal Power Commission, Form 67, Steam-Electric Plant Air and Water Quality Control Data, Annual Report.

Utility Name	Unit Name	Years
Central Illinois Light Co.	Edwards	73-77
Central Illinois Light Co.	Edwards 2	73-77
Detroit Edison Co.	Bay Shore #4	73-74
Detroit Edison Co.	Trenton Channel #9	73-75, 77
Georgia Power Co.	McDonough 1	74, 75, 77
Georgia Power Co.	McDonough 2	74, 75, 77
Illinois Power	Wood River 5	73, 75-77

Note: When both Form 423 data and Form 67 data were available, there were discrepancies, in certain instances, in the data reported in the two forms. Since "theoretically," Form 423 reports data at the time the fuel is delivered to the plant while Form 67 reports these data at the time the fuel is consumed at the plant, we adopted the following guidelines to take care of the discrepancies:

(1) We used Form 67 whenever possible even if it disagreed with Form 423.

(2) If there was no Form 67 for a utility we used Form 423.

IV. VARIABLE: FUEL CODE

Source: Based on fuel consumption data from: Federal Power Commission Form 67, Steam-Electric Plant Air and Water Quality Control Data, Annual Report.

Exceptions: When consumption data were not available, fuel codes were obtained by telephone conversations with the utility or determined by inspecting the fuel consumption in the surrounding years.

V. VARIABLE: SUPERCRITIAL/SUBCRITICAL

Source: Council on Economic Priorities, Power Plant Performance, Nuclear and Coal Capacity Factors and Economics, prepared by Charles Komanoff, in the form of a computer tape, 1976.

VI. VARIABLES: BALANCE DRAFT/POSITIVE PRESSURE

Source: Electrical World, Steam Station Design Survey, reported annually.

Telephone conversations with the utilities.

VII. VARIABLES: BOILER MANUFACTURER, ENGINEER, TURBINE-GENERATOR MANUFACTER

Source: Kidder, Peabody, & Co., Electric Utility Generating Equipment Data Base, in computer tape form, as of November 1980.

Exceptions: For the engineer variables that were missing two other sources were used.

1. Power Engineering, New Generating Plant; a summary of Electric Utility Construction Plans; publications 1967-1979.
2. Telephone conversations with utilities.

VIII. VARIABLES: BOILER CIRCULATION, FURNACE DESIGN, BOILER FEED PUMP DRIVE TYPE.

Source: S. M. Stoller Corporation, SMSC Pedigree Data for Fossil Units, supplied by R. KOPPE.

IX. VARIABLE: EARNED RATE-OF-RETURN ON EQUITY -- THREE YEAR MOVING AVERAGE

Source: Calculation based on Value Line Data Base-II using the following formula:

$$ROE = \frac{NI_t}{(CE_t + CE_{t-1})/2}$$

Where: ROE is rate-of-return on equity

NI_t is net income available for common

CE is reported common equity

t is year

Exception: Data for Tennessee Valley Authority were not available.

Mr. **Fuqua**. Thank you, Dr. Corio.

Mr. Brown, what type of plant equipment requires the most maintenance and repair? What are the biggest problems—turbines?

Mr. **Brown**. I would say boilers.

Mr. **Fuqua**. Boilers?

Mr. **Brown**. In my operating experience many years ago, almost universally boilers create the bigger problems. Very seldom were there problems with generators. Occasionally, there were problems with turbines, but the bulk of the problems were with boilers.

Mr. **Fuqua**. Is there any difference in the reliability effects of burning low-sulfur western coal compared to eastern coal?

Mr. **Brown**. I do not believe I can answer that, but I think I have a related comment, partly from my experience and also from dealing with people who are quite knowledgeable about this business. I think one of the fundamental problems is that people perhaps have not recognized that a boiler is a unique piece of equipment; it is a complex thing. Fundamentally they are designed under precise specifications especially a specific kind of coal. I am told that, whether you are talking low-sulfur or high-sulfur coal, you are talking about a particular vein of coal in many cases. When you shift fuels, the boiler will behave differently, and that is another one of the major contributors to boiler problems.

Mr. **Fuqua**. Dr. Corio, you mentioned the coal ash content. Is that generally the same with eastern and western coals?

Dr. **Corio**. I cannot answer that in terms of the ash content. I know in terms of the Btu content and sulfur content that there are major differences, but I certainly could check that. We did not do a separate analysis on the eastern and western coals, although we did look into some of the characteristics of the coal.

I assume that the results we picked up in terms of coal quality in our model are related to the fact that there are differences in coal quality between the two regions.

Mr. **Fuqua**. Did you do any analysis of plants using different type coal?

Dr. **Corio**. Only to the extent that we included the characteristics of the coal. We did at one point try to separate the sample into those burning eastern and those burning western coal, and we really did not get much further with it than we did when we grouped the two groups together.

Mr. **Fuqua**. In the analysis that you did, what effect did the size of the plant have as far as its reliability is concerned?

Dr. **Corio**. I would like to say a couple of things on that. When we first ran our analysis, we only included three variables—age, size, and vintage—and that is what the industry generally looked at. We found there was a significant size effect. We then introduced what I call that supercritical variable, and we found that the supposed large-size effect the industry talked about was greatly diminished by just adding supercritical into the model.

So what I would say is that we noticed a significant size effect in terms of availability over the 200- to 400-megawatt size, and then after that the size effect is almost minimal.

I would just like to point out that, to the extent that the smaller units are not base-loaded, they would tend to have higher equivalent availabilities only because they can do the maintenance on those units when they are not being run. So you cannot say anything hard and fast about unit size at this point.

Mr. FUQUA. The big 1,000-megawatt plant does not have a great deal more difference than the 400 or the 150?

Dr. CORIO. No. Only if it is supercritical would it make a difference.

Mr. FUQUA. Mr. Brown, you mentioned the NERC regional map and the different regional councils that you have. What is the coordination among the regional companies? Is it adequate?

Mr. BROWN. First of all, the size of some of these councils varies quite widely. Sure, it varies a little bit; it varies in the types of activities that they perform. But we think, from a practical standpoint, the objectives of the councils are being performed. The fundamental objective, of course, is to coordinate the planning so that we keep this network in balance as we expand. Whether that is done in some cases by subregions of a large region or by the total region itself really is not significant.

Of course, as you know, we are really an international council. It happens that, for good and sufficient reason, most of the Canadian-United States interconnections are north and south.

Mr. FUQUA. I notice that in the Western System Coordinating Council you have all the Western States up through British Columbia and Vancouver.

Mr. BROWN. Yes. British Columbia has been part of the Western Council since it was formed.

Mr. FUQUA. But that is a very big land area.

Mr. BROWN. Indeed it is. They call themselves a land area half of total America. I think it is maybe not quite half, but it is awfully close to it; it is a large area.

There are new interconnections being developed in Canada. Saskatchewan Power Corp. and Alberta's system are not very large systems, nor Manitoba as a matter of fact, but they are expanding their interconnections in some cases east and west and in other cases north and south of the border.

Mr. FUQUA. Do you think there is enough coordination going on, or should there be more coordination?

Mr. BROWN. I think it is pretty good. Obviously, you can always do more. We think that, by virtue of the NERC forum, this has encouraged additional coordination. As a matter of fact, we are working on some other projects now at the NERC level. We are working on what we call a reliability criteria task force, looking at the criteria of each of the councils. One of our objectives is to improve the knowledge or the understanding of it outside of the industry, and obviously in the process we will find some improvements, I am sure.

Mr. FUQUA. Are there any major weaknesses between the interconnections?

Mr. BROWN. In the network itself?

Mr. FUQUA. Yes.

Mr. BROWN. I would say not. As you know, I am sure, the Western Council is not in synchronization with the eastern network, nor is Texas at this time in synchronization.

Mr. FUQUA. What do you mean by that?

Mr. BROWN. They are isolated networks. The west is one network operating as a total system. Most of Texas is a separated system. The rest of the councils— the other seven councils, including Manitoba, Ontario, and New Brunswick, are working as if they were all on the same mechanical shaft, you could say.

I know of no major weaknesses. One of the problems, I think, is an understanding of this. We make studies and the various councils and some of the groups of councils make studies. These studies look for the weak points.

Obviously, if you are looking at a network and want to stress it by simulation to find out how far it can go, eventually you will come to a weak point or more properly to the limiting facility. It would be nice if there were stronger interconnections totally, because the better chance you have to help systems in trouble during emergencies.

Mr. FUQUA. We have a vote going on on the floor. We are going to have to take a short break. We will be back in a few moments and resume.

[Recess taken.]

The FUQUA. The subcommittee joint meeting will be in order.

Mr. Skeen, do you have any questions?

Mr. SKEEN. Thank you, Mr. Chairman. Yes, I do. I appreciate the opportunity.

This is a topic that has a great deal of interest for us in the West. I notice the map; I think it is a good illustration, Mr. Brown, of what we are talking about here.

The strange thing to me is that the Western States grew up with a tradition of gridding power because of long transmission lines. Texas, on the other hand, does not, if I am not mistaken.

Mr. BROWN. I am not sure of your question.

Mr. SKEEN. I am referring to netting power. They cogenerate, using the same transmission lines in many States in the West. But strangely enough—am I mistaken?—Texas does not do a lot of that. They are independent generators with their own distribution lines.

Mr. BROWN. No. What we call ERCOT [1] which includes most of the systems in Texas, excluding Amarillo and El Paso and a little bit in the east—essentially, the area defined by Dallas, Houston, Corpus Christi, Austin, San Antonio—that large load area— they are netted.

Mr. SKEEN. They are?

Mr. BROWN. They are networked—oh, yes. They have a good interconnected transmission network.

Mr. SKEEN. At one time I was told that it was an interesting phenomenon in this one generating area. Texas is probably the largest user of electrical energy of any State in the United States, which is interesting to me because it has a large population. It is, I think, one of the highest per capita users of electricity.

Mr. BROWN. I am not sure.

Mr. SKEEN. They grew up with a tradition of being individual generators with individual territories and individual distribution lines. It may be that they have gone into the system, which is far more efficient. But I was just curious because it goes back to this question of reliability.

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[1] ERCOT (Electric Reliability Council of Texas).

With the brownouts that we had in the late 1960's and early 1970's, what would you say is the current percentage of reliability across the United States because of this organization of power?

Mr. **Brown**. I think it depends on how you want to define "reliability."

Mr. **Skeen**. Just in broad terms.

Mr. **Brown**. Percentagewise?

Mr. **Skeen**. Yes, sir.

Mr. **Brown**. It is well above 99 percent by some mathematical calculations.

Mr. **Skeen**. Well over 99 percent?

Mr. **Brown**. Yes, sir.

There is a vast difference between an outage on the bulk power supply and the distribution system which serves neighborhoods.

Mr. **Skeen**. I understand.

Mr. **Brown**. And my concern is that I think we have got to do everything possible to keep from a massive blackout of the transmission system. I am quite aware that the usual reaction of a customer is, "What are you worrying about? I get three or four outages every time it storms in my neighborhood."

I have a way to compare it. To me, it is like a city. The city itself—even New York City—any city has to survive 24 hours a day. You can have a fire in the city, you can have some floods in parts of the city, but the city itself must survive 24 hours a day, 365 days a year. It is my view that that is the concept of the bulk power supply network. We are going to break pieces of it off; there are going to be outages, but the network itself must survive 24 hours a day.

Mr. **Skeen**. Thank you, Mr. Brown. I appreciate that.

Dr. Corio, a question occurred to me. I was very interested in the statement you made comparing nuclear generators and the orders for new nuclear generators to null new orders for new nuclear generators. This is an interesting thing that I wonder if you will corroborate. What about the number of coal-fired generators that are being ordered, as compared to those, say, in the last 5 or 10 years? Is the need going up or going down?

Dr. **Corio**. I really cannot answer on that point, because I have not looked into it. I know that there have been no nuclear ordered since 1976. To the extent that new units are being ordered, they are probably going to be coal.

But I think regulators and utility people are more interested in looking at the existing plant and improving that than even in building new coal plants, and that is really what the issue is.

Mr. **Skeen**. But insofar as new orders are concerned?

Dr. **Corio**. That I really cannot tell you. Maybe Mr. Uhler can help you.

Mr. **Skeen**. Mr. Uhler?

Mr. **Uhler**. One of the things that tends to get overlooked is that there have been very large cancellations or postponements of coal-fired plants. All the emphasis in the newspapers usually is on the cancellation or deferral of nuclear plants and the fact that no new nuclear plants are on order, but not as many megawatts in total, but in numbers of plants there have been 60 percent or 50 percent of the number of megawatts of nuclear plants canceled that were coal-fired plants.

Mr. SKEEN. The point I was getting at was that I suspect, and I think you will find that this is true, that the number of orders for coal-fired plants is down as well. They are not putting in new plants. As you said, with the income picture being what it is in the generating field, there has been a loss of quality of maintenance because of the imbalance of income and the profit structure.

We have a great controversy going on in our part of the country regarding diversification of generating facilities, which means something to me. Given the income picture that in the generating business today, even though these firms are franchised and regulated, they are seeking some way of improving their income picture, even to the point of getting into the oil and gas business, the land business, the water business, and almost any other aspect. Is this a reasonable presentation of finding?

Dr. CORIO. What you say makes sense to me, but I think Mr. Uhler has done some work on this.

Mr. UHLER. Dr. Alfred Kahn was asked to address that point recently in Wisconsin before a group of State regulators, and his findings were, briefly, that there is not an awful lot of statistical information because the electric utility companies themselves are not greatly diversified. Those who had diversified several years ago into coal lucked out because of the increase in oil prices, and so their diversification was successful.

Mr. SKEEN. That is an interesting point. What I am getting at is that the statement has been made to us by many generators from our part of the country that even under the best circumstances and a relatively benign profit return or economic picture, so long as we continue going the way we are going with regulation, the cost requirements inherent in those regulations still insure us that generators, both private, the cooperative type, and the rest, are in big trouble unless something is done to reverse this kind of trend. Is this a fair statement in your opinion?

Mr. UHLER. I think if you look at the financial statistics of the regulated utilities, you will find that most of them have common stock that is selling below book value, and the difference between their allowed rate of return and actual rate of return has worsened over the last few years. In the last couple of days there have been some statements that the industry looks a little bit better and you ought to invest in electric utility common stocks. That is because the electric utility common stocks price has been depressed, and so for today's investor who is looking for a bargain, it might indeed be a bargain, but most financial analysts would agree with your statement, I think, that State regulatory treatment has adversely affected the financial health of the utility industry, and Dr. Corio's analysis shows that that is a causative factor that is linked with declining equipment availability, which certainly has a negative impact on ratepayers, because they are paying more for a kilowatt hour, because the plants are functioning less.

Mr. SKEEN. Thank you very much.

Thank you, Mr. Chairman.

Mr. FUQUA. Thank you, Mr. Skeen.

Mr. Gregg?

Mr. **Gregg**. Thank you, Mr. Chairman.

I was wondering, Mr. Brown, if you can tell me what the attitude of your organization is toward New England States buying Quebec Hydro, or whether your organization has taken any position on that?

Mr. **Brown**. We would not be taking any position on the purchase, per se. Our concern would be to be sure that it is coordinated so that the network that brings this power in will be reliable, which will be done by the region. It will be studied, and a plan will eventually emerge that will make this so. That would be our contribution.

Mr. **Gregg**. You probably are not, but I will ask you just for my information, if you are familiar with the proposed plans to do this with lines running up through New Hampshire and Vermont?

Mr. **Brown**. Yes, generally.

Mr. **Gregg**. Does your organization have a position as to which approach Vermont and New Hampshire——

Mr. **Brown**. No, we would not get into that. The regional council itself may do it. More likely I would think that the New England Power Pool would work on that problem. New England, as you know, has a power pool for planning purposes, so I would assume that they would deal with that.

Mr. **Gregg**. What is your projected growth rate for electricity over the next 2 years, 5 years, or 10 years?

Mr. **Brown**. I would like to add a word to that, too. It shows 3 percent per year—very close to 3 for peak and 3.4 for energy. I would like to add a side comment to that, if I may. That is an average number. That is taking the present level and taking the estimate 10 years from now and doing it with the right kind of mathematics. It is my personal view that it would be helpful if we thought a little bit about it. Part of that percentage will be the restoring of power where switches are now turned off. The weakness in the electric load areas in the industrial area—the residential loads have been growing; commercial have been growing; industrials have been negative at various times.

My point is that it will look like growth. That is just restoring load that has been there before, and the rest will be growth, in my view.

Mr. **Gregg**. Back in the early 1970's, were we not using an estimated 7 percent growth rate?

Mr. **Brown**. Yes, typically, up until, let us say, 1970, it was 7 percent per year overall.

Mr. **Gregg**. With that change in the estimated use of electricity, what does that forebode for new plants, especially nuclear?

Mr. **Brown**. In the amount of capacity needed to carry the peak load, we have got to carry the load 8,760 hours per year. So we are not building capacity only for peak; it is there to carry kilowatthours all the year around.

Mr. **Gregg**. I guess my question is, what do you perceive is the need for construction?

Mr. **Brown**. Whether we need to build?

Mr. **Gregg**. Right.

Mr. **Brown**. Definitely, of course.

Mr. GREGG. How much?

Mr. BROWN. I do not have a very good crystal ball.

I would like to see us—and by us, I mean the utility industry and everybody else—I would like to see us make a commitment to a building program and get with it. My personal concern would be that we drift into a shortage, and it will be a catastrophe. I would like to see us have a program where at least we will not have a catastrophe due to a shortage of power. Operating people have lots of tricks in the bag. In operating this network, there are all kinds of things that happen. They deal with emergencies all the time.

Given a good network and the coordination and operation, which is probably even better there than in planning, there are lots of things that can be done.

We have a favorite term—the diversity of adversity. In other words, because we have a good network, when machinery fails here, there, or somewhere else, there is power in the network to support it and provide the emergency power.

So I would hope that we have a program that would at least keep up from having a catastrophe.

Mr. GREGG. You do not have figures though?

Mr. BROWN. No, sir.

Mr. GREGG. Yes?

Mr. Brown. Are you talking about how many megawatts need to be built? I believe our last report showed numbers on the order of 150,000 megawatts in 10 years, which was roughly, as I recall, about 100,000 megawatts coal and 50,000 megawatts nuclear. Now, these keep getting scaled down, but on that order. I believe my numbers are right; I am not positive on that.

Mr. GREGG. Dr. Corio, first I want to thank you for your presentation. I appreciate the way you made it— concise and to the point.

You mentioned low-sulfur fuel versus high-sulfur fuel as not having any efficiency effect on the pollution control devices that were on the facilities. Is that what you were referring to?

Dr. CORIO. No. What I am saying is that it seems to me that sulfur has a positive effect and a negative effect, and in my results the negative effect dominated.

Mr. GREGG. Would you repeat that?

Dr. CORIO. OK. In one sense we would expect sulfur to have a positive effect on performance, because it helps the electrostatic precipitators to run better. On the other hand, at the same time some of the sulfur would form sulfuric acids and would corrode, from what I understand, some of the heat recovery equipment near the stack.

So we have these two effects of sulfur, and now what my results show is that, if you will look at the positive effects versus the negative effects, the combination of the two is still negative. In other words, the negative still outweighs the positive effect.

Mr. GREGG. So what you are saying is that we should burn low-sulfur fuels even in high-sulfur-designed furnaces?

Dr. CORIO. The only reason I am hesitating is that the words "high-sulfur-designed furnaces" are not something that is explicitly taken into account in this model, but on average that is what these results seem to suggest—yes.

Mr. GREGG. We should be burning low sulfur?

Dr. CORIO. Yes.

Mr. GREGG. Did you take into consideration fluidized bed?

Dr. CORIO. No, I have not.

Mr. GREGG. I assume that is because there are not enough around to really be able to get a good sample.

Dr. CORIO. That is something we are going to be considering. We have now started working with EPRI on further refining this model, and that is some of the stuff that we will be looking at.

From what I understand, when you do things like wash the coal to get rid of some of the sulfur, you also change other characteristics of the coal, so it may not always be as beneficial as you think. For example, in that case you could lower something called the ash-fusion temperature of the coal, and that would be—you would introduce another problem at the same time. We are looking into the tradeoffs.

Mr. GREGG. But basically you are concluding that you get a more efficient burn from using low sulfur?

Dr. CORIO. At this point we are.

Mr. GREGG. Thank you.

Mr. FUQUA. Thank you very much, Mr. Brown and Dr. Corio. We appreciate your testimony and your being with us here today. We hope we have no brownouts this summer.

Mr. BROWN. We will do our best.

Mr. FUQUA. Our next panel of witnesses will consist of Dr. Zack T. Pate, Dr. A. D. Patton, and Mr. Kerner Smith.

Dr. Pate, we would be pleased to hear from you at this time. Without objection, your prepared statement will be included in the record.

STATEMENT OF DR. ZACK T. PATE, VICE PRESIDENT, OPERATIONS, INSTITUTE OF NUCLEAR POWER OPERATIONS

Dr. PATE. Thank you.

I am Zack T. Pate, vice president, operations, of the Institute of Nuclear Power Operations.

First, I am pleased that the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production are holding hearings on the reliability of electric power in this country. I appreciate this opportunity to comment on the Institute of Nuclear Power's efforts to contribute to safety and reliability of nuclear electric generation.

The Institute of Nuclear Power Operations' [INPO] mission is to promote the highest standards of safety in nuclear plant operations. Experience has shown that safety and reliability are inseparable. We are convinced that they are directly related and interdependent and that efforts to improve safety invariably improve reliability.

The nuclear electric utilities in this country recognize that high standards are essential in the operation of their plants, and they have taken steps to ensure and improve safety and reliability. I would like to discuss some of these actions today, and I will concentrate on the activities the industry is taking through the Institute of Nuclear Power Operations.

INPO is a nonprofit organization established by the Nation's nuclear utilities to promote the highest standards of excellence. INPO is a direct response by the industry to the accident at Three Mile Island. The utility industry formed INPO to apply the lessons learned from that experience and to help improve overall safety in the operation of nuclear plants.

The lessons learned from Three Mile Island provide the starting point for the definition of INPO's role in the industry. Four major lessons were identified: a need to improve operator training, a need to improve and achieve excellence in the day-to-day operation of nuclear plants, a need for better analysis of operating plant experience and improved dissemination of the lessons learned, and a need to improve the industry's ability to cope with emergencies.

INPO's technical divisions are structured along the lines of these "lessons learned."

Funding for INPO is provided by its members and participants. INPO members are utilities that own or operate nuclear plants for the purpose of generating electricity. Every U.S. utility with an operating license or a construction permit is a member. In addition, 12 foreign utilities participate in INPO. Other participants include nuclear steam supply system vendors and architect engineering firms.

INPO is organized along the lines of a typical U.S. corporation. The president of INPO, Dennis Wilkinson, is also the chief executive officer. The INPO board of directors consists of 11 members. Nine are senior utility executives, and two are nuclear plant managers. The current board chairman is Mr. Lelan F. Sillin, Jr., chairman and chief executive officer of Northeast Utilities.

As INPO's programs have developed, its staff has grown. As of June 4, 1982, INPO's total staff numbered 278.

The foregoing has provided a brief introduction to INPO, and I will now outline our technical programs.

We have four technical divisions—training and education, analysis and engineering, evaluation and assistance, and radiological protection and emergency preparedeness. I will describe some of the key programs under the cognizance of these divisions.

The training and education division is involved in several programs designed to assist member utilities in acquiring, training, and qualifying personnel to operate maintain, and support nuclear plants.

To assist the industry with manpower planning, INPO, with contractor funding provided by DOE, conducts annual surveys of employment and training in the industry. Individual utility and aggregate data are used to identify significant staffing problems and trends. This information is provided to member utilities to assist them in their planning and staffing efforts. INPO does not hesitate to urge a member utility to increase their staffing in areas where needs are identified.

As a part of the overall manpower effort, INPO manages a utility-funded educational assistance program to encourage engineering students to pursue careers in the nuclear industry. For the 1981-82 school year, for example, the industry, through INPO, awarded $591,000 in scholarships to 43 graduate and 165 undergraduate engineering students majoring in fields applicable to nuclear electricity generation.

The second activity of the Training and Education Division is development of training standards for the industry. Establishment of quality training standards is being approached in two phases. In the first, INPO developed guidelines based on the best programs and practices existing in the U.S. nuclear industry. These have been published and distributed to member utilities, and the training organizations are using them to develop or modify their training programs. This first phase is now complete.

The second phase involves a comprehensive and systematic analysis of training and education needs of powerplant personnel. Job and task analysis techniques are being employed to identify detailed training requirements. The results will be used to improve the training guidelines and complete the development of an overall model training program. This program and the job and task analysis data base will be made available to member utilities to aid them in designing and improving their plant-specific training programs.

Two major activities related to the development of training standards are accreditation and evaluation programs. In the accreditation process, INPO examines the programmatic and procedural aspects of a utility's training program. As part of our regular plant evaluation program, which I will discuss in a moment, INPO examines the implementation and effectiveness of the training programs. This includes assessing actual, on-the-job performance of plant personnel. In combination, these two programs are intended to ensure that nuclear plant personnel are well trained and properly qualified for their jobs.

The accreditation program will be similar to the process used to accredit educational institutions. The basic concepts have been retained, but the procedures and content have been adapted to the industrial training environment. Implementation of the accreditation program will begin this year.

A major activity of INPO's Analysis and Engineering Division is the significant event evaluation and information network program. This program provides for the analysis of nuclear plant operating events and the distribution of lessons learned. Reports of operational events with potential safety significance are submitted to the Nuclear Regulatory Commission. These reports are called licensee event reports or, commonly, LER's. Copies are provided to INPO. These LER's—over 2,000 a year—and supplementary information are analyzed to identify recurring problems and possible precursers of more serious events.

After significant event information is disseminated, the utility determines the changes in equipment, procedures, or training that are necessary to apply the lessons learned from that event.

Many significant events are found to be repeats of prior similar events. The timely implementation of corrective action can reduce the frequency or severity of such events and the occurrence of extended outages often associated with some of these events, thus contributing directly to reliability of the electrical supply.

A major facet of INPO involvement in the nuclear industry is the evaluation and assistance program. The first round of operating plant evaluations was completed in 1981—50 operating stations in all. INPO is now into the second round of evaluations of these plants. In addition, INPO has initiated assistance visits to near-term operating license plants and will soon begin corporate assistance visits.

The evaluations are conducted to assess the knowledge and performance of station personnel, the condition of systems and equipment, the quality of programs and procedures, and the effectiveness of station management. The focus is on plant safety and reliability.

Performance objectives and criteria have been developed. These objectives and criteria and the experience of INPO evaluators serve as the basis for evaluations. A great deal of emphasis is placed on INPO's experience in observing best practices in the industry.

The objectives and criteria have been provided to INPO members, and they are encouraged to look at themselves within that framework. A number of utilities have found this effort enlightening and beneficial.

Evaluation teams are led by a team manager and typically include 10 evaluators. Collectively, INPO has a wealth of experience in the areas it evaluates. Permanent INPO employees from nuclear utilities have experience as plant managers, operations superintendents, maintenance superintendents, and in other areas of the nuclear industry. Former Navy nuclear personnel are on staff with experience in all phases of plant operations, and several have experience in conducting operational reactor safeguards evaluations of nuclear ships. A number of personnel gained experience with the Nuclear Regulatory Commission and others in various nuclear-related industries. Many of our evaluators have experience in more than one of these categories.

Evaluation work begins with 2 weeks of preparation. The site work itself takes the better part of 2 weeks. During that period the team managers conduct daily meetings to analyze and develop observations made by the evaluators.

The evaluator in each area maintains close communications with his department back in Atlanta. This allows a team in the field to call on the full resources of INPO. Field work then culminates with an exit meeting with plant and corporate management. Each evaluator having lead responsibility for an area such as operations, maintenance, or radiological protection presents his findings. A senior representative from INPO then summarizes the team's most important findings, including strengths and weaknesses. Questions from the utility are answered. The exit meeting is conducted with candor and in a spirit of cooperation.

As INPO learns from the evaluation and assistance program, it works to pass the lessons learned and best practices on to the industry. Invariably, the results are aimed at improving or enhancing some aspect of nuclear station management or supervision. The industry is supportive of this process, and its responsiveness to INPO initiatives is evident in ongoing programs to improve safety and reliability. To the extent INPO is successful in stimulating improved management and supervision, our efforts are multiplied many times over.

We are a small organization. To be really successful, we must achieve success in stimulating improved management and supervision and in getting each utility to continually evaluate itself against the highest standards.

The activities of the institute which I have just described represent a unique and considerable effort by a U.S. industry to promote safety and reliability, and to insure the protection of industry employees and the public.

Over recent decades there has been an increasing involvement of Government in the regulation and control of various U.S. industries. In my opinion, this has not always led to improved safety, reliability, and quality. It now appears that the Congress and the administration are moving to reduce the involvement of Government. I am pleased to be associated with an organization that could serve as an example of the kind of industry initiatives needed to allow reduction in Government control and regulation.

I am impressed and encouraged by the insight of this committee and your determination to insure a reliable supply of electricity for our country. As stated earlier, the Institute considers that efforts to improve safety and reliability are fully complementary. To that end, we pledge continued vigilance.

Thank you for allowing me to comment.

[The prepared statement of Dr. Pate follows:]

Statement to

Subcommittee on Energy Development and Applications
and
Subcommittee on Energy Research and Production
of the

House Committee on Science and Technology
U. S. House of Representatives

Zack T. Pate
Vice President, Operations
Institute of Nuclear Power Operations

June 10, 1982

INTRODUCTION

I am Zack T. Pate, vice president, operations, of the Institute of Nuclear Power Operations. My biographical summary is attached.

First, I am pleased that the Subcommittee on Energy Development and Applications and the Subcommittee on Energy Research and Production are holding hearings on the reliability of electric power in this country. I appreciate this opportunity to comment on INPO's efforts to contribute to safety and reliability in the operation of nuclear electric generating plants.

The security and the economy of this nation are dependent on reliable electric power. It is, therefore, of critical importance that government and industry work together to ensure that the nation's needs for electricity are met, and that the necessary electricity is generated safely and reliably. The Institute of Nuclear Power Operations' mission is to promote the highest standards of safety in nuclear plant operations. Experience has shown that safety and reliability are inseparable. We are convinced that they are directly related and interdependent, and that efforts to improve safety invariably improve reliability. The converse is, of course, also true. In carrying out INPO's programs, we do not try to distinguish between the two; we seek to improve both.

The nuclear electric utilities in this country recognize that high standards are essential in the operation of their nuclear plants, and they have taken steps to ensure and improve safety and reliability. I would like to discuss some of those actions today, and I will concentrate on the activities that the industry is taking through the Institute of Nuclear Power Operations.

BACKGROUND

The Institute of Nuclear Power Operations (INPO) is a non-profit organization established by the nation's nuclear utilities to promote the highest standards of excellence for operating nuclear electric generating stations. INPO is a direct response by the nuclear utility industry to the accident at the Three Mile Island (TMI) Nuclear Plant on March 28, 1979. The utility industry formed INPO to apply the lessons learned from that experience and to help improve overall safety in the operation of nuclear plants.

As early as ten days after the accident, the nuclear utilities established a TMI Ad Hoc Nuclear Oversight Committee to coordinate industry response to the accident. Represented on the committee were investor-owned utilities, public utilities, and cooperatives. A few days later, on April 16, the Atomic Industrial Forum established a broad-based organization called the Policy Committee on Follow-Up to the TMI Accident. This committee included nuclear steam supply system vendors and architect-engineering firms, as well as utilities. The Electric Power Research Institute (EPRI) was asked to develop an approach for evaluating the TMI accident and to recommend improvements in nuclear plant safety. Two new organizations were initiated as a direct result of these activities. One was the Institute of Nuclear Power Operations and the other was the Nuclear Safety Analysis Center (NSAC), which became a part of the Electric Power Research Institute.

The industry moved quickly. By late June 1979, the chairman of the TMI Ad Hoc Nuclear Oversight Committee announced the industry's intent to form INPO. Dr. Chauncey Starr of the Electric Power Research Institute was given the task of pulling together a proposed organization plan. Within three months, the plan was thoroughly discussed with the industry and issued in final form. Before the end of 1979, INPO was formally incorporated, a board of directors was selected, and Eugene P. (Dennis) Wilkinson was named president. Atlanta was chosen as the permanent headquarters.

The lessons learned from the Three Mile Island accident provided the starting point for the definition of INPO's role in the industry. Four major lessons were identified. These were as follows:

- a need to improve operator training
- a need to improve and achieve excellence in the operation of nuclear plants
- a need for better analysis of operating plant experience and improved dissemination of the lessons learned
- a need to improve the industry's ability to cope with emergencies

INPO's technical divisions are structured along the lines of these "lessons learned."

Funding for INPO is provided by its members and participants. INPO members are utilities that own or operate nuclear plants for the purpose of generating electricity. Every U. S. utility with an operating license or a construction permit for a nuclear power plant is a member. In addition, 12 foreign utilities (or organizations) participate in INPO. Other participants include nuclear steam supply system vendors and architect-engineering firms. The 1982 budget for INPO's operations is $32 million.

INPO is organized along the lines of a typical U. S. corporation. The president of INPO is the chief executive officer. There are four technical and two support divisions. The technical divisions are Training and Education, Evaluation and Assistance, Analysis and Engineering, and Radiological

Protection and Emergency Preparedness. The support divisions are Communications and Administration. INPO currently has two special programs, the International Program and the Construction Project Evaluation Program. The latter was recently assigned to INPO by the utility industry and is under development.

The INPO board of directors consists of eleven members. Nine of the members are senior utility executives. The INPO by-laws specify that two directors must have recent experience in the supervision of a nuclear facility. Accordingly, two of the board members are nuclear plant managers. The current board is chaired by Lelan F. Sillin Jr., chairman and chief executive officer of Northeast Utilities.

In addition to the board of directors, INPO has an eighteen-member advisory council composed of individuals with expertise in the design and operation of nuclear plants, education in scientific or high technology fields, safety analysis, behavorial and human sciences, training operators of complex systems, or environmental and medical sciences. The advisory council is chaired by Dr. Thomas H. Pigford, Professor of Nuclear Engineering, University of California at Berkeley.

To ensure that INPO programs benefit from the best technical advice the nuclear industry has to offer, each technical division of INPO has a nine-member Industry Review Group. The members of these groups are experienced personnel who are currently active in nuclear plant operations or management. They review INPO programs and products on a continuing basis and provide advice to the division directors.

As INPO's programs have developed, its staff has grown. As of June 4, 1982, INPO's total staff numbered 278. The professional staff at INPO numbers 211, of that number 46 are on loan to INPO from utilities in the U.S.

and abroad for periods of a year or more. An additional 26 people are currently on loan to INPO for a brief period to assist in the development of the Construction Project Evaluation Program.

A major INPO objective is to facilitate the communication of technical information within the nuclear industry. Three major data bases support that information exchange. The first, NUCLEAR NOTEPAD, is a computer teleconferencing system that links all INPO members and participants. The industry uses it to transmit information on dedicated channels covering areas such as significant operating events, maintenance techniques, emergency planning, and quality assurance.

INPO has recently been assigned management of the Nuclear Plant Reliability Data System (NPRDS). This is a computer-based system designed to collect and analyze performance and reliability data on safety-related nuclear systems and components.

Third, the industry has access through INPO to computer-stored licensee event reports that relate information about operating experiences at nuclear plants throughout the United States.

In addition to the data bases available for industry use, INPO conducts workshops and conferences and develops publications that help to keep the industry informed.

The foregoing has served as a brief introduction to INPO, its history, the rationale for its major programs, and its organization and staffing. The technical programs will now be described.

MAJOR PROGRAM REVIEW

A. Training and Education Division

INPO is involved in several programs to assist member utilities in acquiring, training, and qualifying personnel to operate, maintain, and support nuclear plants.

1. Personnel resources

INPO, with contractor funding provided by the Department of Energy, conducts annual surveys of employment and training in the nuclear utility industry. These industrywide surveys determine current and projected employment, vacancies, and turnover in nuclear-related positions at member utilities. They also determine the sources of personnel, training lead times, and the number of personnel currently in training for key plant operations, maintenance, and technical support positions. Individual utility and aggregate industry data is used to identify significant staffing problems and trends. This information is provided to member utilities to assist them in their planning and staffing efforts.

2. Educational assistance

For the past two years, the nuclear utility industry has funded and INPO has managed an educational assistance program to encourage engineering students to pursue careers in the nuclear power industry. For the 1981-1982 school year, the industry, through INPO, awarded $591,500 to 43 graduate and 165 undergraduate engineering students majoring in fields applicable to nuclear electricity generation.

3. Training guidelines

To assist utilities in developing and improving their training programs, INPO is developing training program guidelines for the training and qualification of personnel. These guidelines are based on organizational structures and job positions that are typical in the industry, and they must be adapted to each utility's situation. The establishment of quality training standards is being approached in two phases. In the first phase, INPO developed guidelines based on the best programs and practices in the U.S. nuclear industry. In the second phase, INPO is developing a model training program based on a comprehensive and systematic analysis of training and education needs.

To develop training guidelines, the INPO staff reviewed written program descriptions, visited and evaluated plant training organizations, conducted workshops, and selected the best elements from existing industry programs. INPO training and qualification guidelines have been developed for nuclear power plant operation, maintenance, technical support, and training positions. In general, these guidelines describe the education and training recommended for workers who directly influence nuclear plant safety. These guidelines have been published and distributed to member utilities. Member utilities actively participated in the guideline development, and their training organizations are using them to develop or modify their training programs. This first phase is now complete.

4. Job and task analysis

The second phase involves a comprehensive and systematic analysis of the training and education needs of nuclear power plant personnel. Job and task analysis techniques are being employed to identify detailed training requirements. The results will be used to improve the training guidelines and complete the development of an overall model training program. This program and the job and task analysis data base will be made available to member utilities to aid them in designing and improving their plant-specific training programs. Task analysis results could also aid in improving the reactor operator licensing examinations and related training regulations.

INPO's job and task analysis project began in mid-1980 with the development of detailed plans and initial data gathering. In conjunction with the U.S. Department of Energy, which provided funding, a contract was awarded in January 1981 to perform the initial job and task analysis for licensed operator positions. Many of INPO's member utilities are participating in and have committed significant resources to this project. Job analysis has been completed for eight operations, maintenance, and technician job positions at light water reactors. Task analysis is in progress for the licensed operator positions and is planned for the other positions in the near future.

5. Accreditation and evaluation of training

Two major INPO activities related to the development of training standards are the accreditation and evaluation efforts. In the accreditation process, INPO examines the programmatic and procedural aspects of the utility's training program. As part of the plant evaluation program, which will be discussed in detail later, INPO examines the implementation and effectiveness of the utility's training program. This includes assessing actual on-the-job performance of plant personnel. In combination, these programs are intended to ensure that nuclear power plant personnel are well trained and properly qualified for their jobs and that their knowledge and ability are continuously maintained and upgraded.

The INPO accreditation program will be similar to the process used to accredit educational institutions. The basic concepts have been retained, but the procedures and content have been adapted to the industrial training environment. The INPO accreditation process consists of three major steps. In the first step, the utility performs a detailed self-evaluation of its training activities and programs against INPO-published criteria. During the self-evaluation, the utility identifies and begins correcting any weaknesses in its training programs. A report of the self-evaluation findings is submitted for review. Thereafter, a team of INPO staff members and industry training experts visits the training site for several days, observing training activities, interviewing training personnel and others, examining facilities and material, and reviewing records and procedures. The team then prepares a report of its conclusions and recommendations. In the last step, the Accrediting Board, composed of utility representatives and training and education experts, decides whether to award or defer accreditation. Implementation of this program will begin this year.

B. Analysis and Engineering Division

The major activities of INPO's Analysis and Engineering Division include the Significant Event Evaluation and Information Network (SEE-IN) program, the management of the Nuclear Plant Reliability Data System (NPRDS), coordination of INPO's governmental relationships, and work in other selected areas.

1. Event analysis

The Significant Event Evaluation and Information Network provides for the analysis of nuclear plant operating events and the distribution of lessons learned. Reports of operational events of potential safety significance are submitted to the Nuclear Regulatory Commission (NRC) by each utility. These are called Licensee Event Reports (LERs). Copies are provided to INPO. These LERs, over 2000 a year, and supplementary information are analyzed to identify recurring problems and possible precursors of more serious events. To ensure thorough coverage, each event undergoes at least two independent reviews at INPO. Significant Event Reports (SERs) are the output of this screening process. SERs are distributed by NUCLEAR NOTEPAD to provide early notification of operating problems to all utilities.

Selected events are further analyzed to produce Significant Operating Experience Reports (SOERs). These more comprehensive reports include recommendations designed to reduce the likelihood or the consequences of a similar event. They are classified into three categories according to their relative importance to nuclear plant safety.

INPO also conducts in-depth reviews of major events that warrant extensive analysis. This usually involves on-site collection of background information and data needed for an in-depth analysis.

After significant event information is disseminated, the utility determines the changes in equipment, procedures, and/or training that are necessary to apply the lessons learned from the event. The adequacy of utility actions in response to event reports is reviewed during regular INPO plant evaluations.

Many significant events are found to be "repeats" of prior, similar events. The timely implementation of corrective action can reduce the frequency or severity of such events and the occurrence of extended outages often associated with some of these events, thus contributing directly to the reliability of the electrical supply.

2. Nuclear Plant Reliability Data System

In January of this year, INPO was assigned responsibility for the management and technical direction of the industry's Nuclear Plant Reliability Data System. The Edison Electric Institute and public power nuclear operators continue to co-fund this work with INPO through 1982. INPO will assume full responsibility for funding of this program in 1983. The industry and the NRC will continue to have representation on the NPRDS Data Usage Working Group.

INPO staff personnel are systematically using NPRDS engineering and failure data to augment INPO's reviews of significant operating events. Additional workshops and conferences have been scheduled to increase utility participation and to facilitate the use of this important data base. Simplified methods for input of data are being developed, and on-line access by INPO members and participants is planned later in 1982.

3. Governmental relationships

INPO has developed a number of working relationships with DOE and NRC. With DOE, INPO has a participation agreement that includes INPO representation on DOE working groups. DOE is also jointly funding some aspects of NPRDS, as well as the manpower and training activities previously described. INPO and NRC are coordinating activities in a number of areas. A memorandum of agreement has been signed covering selected event analysis activities. NRC has formally recognized the INPO-managed SEE-IN program.

4. Miscellaneous

Other projects in the Analysis and Engineering Division include the following:

a. Operator Aids for Severe Accidents

INPO is assisting a utility working group in the development of guidelines for the integration of Emergency Operating Procedures with Safety Parameter Display Systems (SPDS). Development of appropriate training programs will be included in this effort.

b. Control Room Design Review

INPO and member utilities are investigating the feasibility of an industry effort to provide practical objectives and methods of approach to control room improvements. This effort is aimed at providing a basis for prioritizing changes and at providing criteria that can help avoid changes that may be counterproductive. An initial pilot project has been undertaken jointly with TVA, and the results will be published this summer.

c. Plant Procedures

INPO has initiated a program aimed at providing guidance for drafting clear and effective plant procedures that are user-oriented. The first phase of this program is directed at the development, validation, and implementation of emergency operating procedures. INPO has undertaken this effort in support of a working group that bridges the subcommittees of the four nuclear steam supply system owners groups dealing with emergency operating procedures.

d. Human Error Reporting and Analysis

A pilot project - with three utilities - is in progress to develop and test classification systems. This involves developing procedures for gathering data on the human sensitivities involved in reporting errors. The practical remedies to reduce the rate of human errors cover a range of issues, many of them involving supervision and management as well as operator training and procedures.

C. Evaluation and Assistance Division

A major facet of INPO involvement in the nuclear power industry is the evaluation and assistance program. The first round of operating plant evaluations was completed in 1981 - fifty stations in all. INPO is now into the second round of evaluations of these operating plants. In addition, INPO has initiated assistance visits to near-term operating license plants, and will soon begin corporate assistance visits.

1. Operating plant evaluations

These evaluations are conducted to assess the knowledge and performance of station personnel, the condition of systems and equipment, the quality of programs and procedures, and the effectiveness of station management. The focus is on plant safety and reliability.

The following areas are evaluated:

- organization and administration
- operations
- maintenance
- technical support

- o training
- o radiological protection
- o chemistry
- o event analysis

An INPO department has cognizance of each of these eight areas. One department's role, the Radiation Protection Department, is described in some detail in the next section. Performance objectives and criteria have been developed to cover these eight areas. These objectives and criteria and the experience of INPO evaluators serve as the basis for evaluations. A great deal of emphasis is placed on INPO's experience in observing the best practices in the industry. Objectives and criteria have been provided to INPO members, and they are encouraged to look at themselves within that framework. A number of utilities have found this effort enlightening and beneficial.

2. The evaluation process

Evaluation teams are led by a team manager and typically consist of about ten evaluators. Collectively, INPO has a wealth of experience in the areas it evaluates. Permanent INPO employees from nuclear utilities have experience as plant managers, operations superintendents, maintenance superintendents, shift supervisors, and in other areas in the nuclear utility industry. Former Navy nuclear personnel are on staff with experience in all phases of plant operations, and several have experience in conducting operational reactor safeguards evaluations of nuclear ships. A number of personnel have gained experience with the Nuclear Regulatory Commission, and others in various nuclear-related industries. Many evaluators have experience in more than one of these categories. In addition, of the 46 people currently on loan from member utilities, about half are involved in the evaluation program. This program is important to INPO. It brings in directly applicable expertise from the field, and in turn, the loaned employee returns to his utility with valuable experience.

Evaluation work begins with about two weeks of preparation. Evaluators study information on plant performance and other pertinent data and become acquainted with the station organization and plant policies and procedures. A schedule is developed in advance to expedite the site evaluation activities.

The site work itself takes the better part of two weeks. During that period, team managers conduct daily meetings to analyze and develop the observations made by evaluators. The evaluator in each of the eight areas listed in 1. above also maintains close communications with his department manager back in Atlanta. This allows the team in the field to call on the full resources of INPO. Field work culminates with an exit meeting with plant and corporate management. Each evaluator having lead responsibility for an evaluation area, such as operations, maintenance, or radiological protection, presents findings in his area. A senior representative from INPO then summarizes the team's most important findings, including both strengths and weaknesses. Questions from the utility are answered. The exit meeting is conducted with candor and in a spirit of cooperation.

3. The evaluation report

Field work is followed by report preparation. The first draft of the report contains essentially the same information presented at the exit meeting; however, recommendations are provided for each finding. To this first draft the utility adds responses indicating how the recommended improvements have been or will be achieved. Once the responses are reviewed at INPO and discussed with the utility, the final report is issued.

Discussion of the utility's responses to each finding and recommendation is often one of the most productive parts of the evaluation process.

The utility provides a status report six months after the report is issued and a final update just prior to the next evaluation. During the second and each succeeding evaluation, the evaluation teams follow up to see that improvements recommended in the last report have actually been achieved. Fourteen of the second-round evaluations have been completed, and the entire second series is expected to be finished by the end of the first quarter of 1983. Responsiveness to the first-round evaluations is encouraging. It is clear that improvements have been made, and efforts to initiate further improvements are in progress.

4. Assistance visits to near term operating license (NTOL) plants

In January, INPO began assistance visits to near-term operating license plants. The purpose of these visits is to assist the utility in preparing to operate. Methods are similar to those used in the operating plant evaluations.

5. Corporate Evaluations

A developing aspect of the evaluation and assistance program is the planned expansion into corporate support and monitoring of nuclear stations. INPO will extend the scope of evaluation and assistance visits to cover this area over the next several months. An ad hoc committee of utility executives assisted INPO in developing performance objectives and criteria for corporate evaluations. Some of these executives are accompanying the teams on a series of pilot evaluations. They are acting as advisors during the actual implementation of this program.

6. Coordination with NRC

INPO has had considerable interaction with the Nuclear Regulatory Commission regarding coordination of selected NRC appraisal and INPO evaluation activities. INPO believes that its evaluation activities are supportive of the NRC's regulatory role and, at the same time, can significantly lessen the burden imposed on the nuclear utility industry by duplicative appraisal and evaluation activities. In this regard, INPO and the NRC are working to achieve economy in their efforts to enhance plant safety and reliability. Coordination of NRC and INPO appraisal and evaluation activities appear to us to be proceeding well.

7. Development of Good Practices

In support of the overall evaluation and assistance program, the evaluation team members collect and analyze information to produce a number of useful results. For example, brief documents entitled Good Practices are developed. These documents cover selected areas of plant operations and management. They are based on programs the evaluation team finds to be working well at nuclear stations and on the collective experience of the INPO staff.

8. Summary

As INPO learns from the evaluation and assistance program, it works to pass the lessons learned and best practices on to the industry. Invariably the results are aimed at improving or enhancing some aspect of nuclear station management or supervision. The industry is supportive of this process, and its responsiveness to INPO initiatives is clearly evident in ongoing efforts to improve safety and reliability. To the extent INPO is successful in stimulating improved management and supervision, INPO's efforts will be multiplied many times over. INPO is a small organization; to be really successful, it must achieve success in stimulating improved management and supervision and in getting each utility to continually evaluate itself against the highest standards.

D. Radiological Protection and Emergency Preparedness Division

The Radiological Protection and Emergency Preparedness Division at INPO is involved in a number of programs. The Radiological Protection Department is directly involved in the plant evaluations carried out by the evaluation and assistance division.

1. Emergency Preparedness

The Emergency Preparedness Department conducts a program of site visits to review emergency preparedness activities and observe exercises in order to provide assistance to utilities. The INPO Communications Division cooperates in this effort to review emergency public information programs at utilities.

Emergency preparedness teams review the following major areas:

- emergency operating organization
- emergency plan
- emergency response training
- emergency facilities
- emergency assessment and notification
- emergency personnel protection
- emergency public information

This is accomplished by reviewing plant and corporate procedures and records, by inspections of emergency equipment, and by interviewing appropriate people.

A typical review and assistance visit is conducted about four months prior to a utility's annual exercise or drill. INPO spends a week at the utility with a three- to four-person team. At least one day is spent at the corporate headquarters. A formal exit meeting is held. The team returns to the utility at the time of the annual exercise and observes. After the exercise, the team meets with the utility to again offer any suggestions to improve the emergency plan.

To further assist the utilities in the emergency preparedness area, INPO operates and maintains an Emergency Response Center that has 24-hour a day coverage. Through this center, INPO can offer utilities the following emergency support functions:

- assistance to the affected utility in locating sources of emergency manpower and equipment
- dissemination of information concerning the incident to other utilities
- organization of industry experts who could advise the affected utility on technical matters

INPO prepares and distributes to member utilities an Emergency Resources Manual. This is a compilation of information on the equipment and manpower available at each utility that can be called upon in an emergency. This manual is designed to help identify and expedite the acquisition of available resources should the need arise.

INPO has also served as a catalyst in developing two assistance agreements among utilities. One is in the area of transportation accidents and the other is for nuclear plant emergencies. The agreements prearrange assistance among the participating utilities and thus should speed up response.

2. Radiological Protection

The Radiological Protection Department is involved in the protection of both workers and the public from radiation exposure, and in the area of plant chemistry. Radiation protection is one of the areas most carefully scrutinized by INPO during a plant evaluation. INPO strives to assist its member utilitites in achieving excellence in this important area. The goal is to operate in such a manner that it can be demonstrated to workers and the public that exposure to radiation at the work site is minimized, unnecessary radioactive waste is not generated, and the release of radiation to the environment is minimized.

To evaluate a plant's performance in this area, INPO draws on a staff with over 200 man-years experience in radiological protection at nuclear plants. Experience has shown that management and worker involvement at all levels and in all departments at a nuclear station is necessary to achieve a well-run radiological protection program. Accordingly, INPO's evaluations are not limited to the plant group specifically assigned that function. In addition to performing a technical review of these programs, INPO evaluators spend much of their time observing actual on-the-job work in radiologically controlled areas and the handling of radioactive material. The competence with which these activities are performed serves as an important element in an overall program assessment. An evaluation of a plant's radiological protection is normally broken down into the following areas:

- organization and administration of the radiological protection program
- the qualification of radiological protection technical personnel
- the conduct of general employee training in radiological protection

- controls over external exposure from radiation
- controls over exposure from radioactivity inhaled or ingested
- controls over radioactive effluent released to the environment
- controls over the generation of solid radioactive waste
- the monitoring of individual radiation dose
- controls to prevent spreading of radioactive contamination within the plant

Each of these areas is evaluated at every nuclear plant. In addition to relying upon an individual evaluator's knowledge and experience, the observations and findings are thoroughly reviewed, analyzed, and critiqued by the INPO radiological protection staff during the course of each evaluation. This enables each evaluator to draw on a large pool of knowledge and experience to ensure a more thorough and competent evaluation.

Subsequent to an evaluation, nuclear plants are often provided technical assistance in solving some of the problems identified. Normally this is done through providing written technical information. On a case basis, however, INPO staff visits are requested by the utility to assist in addressing specific problem areas.

3. Chemistry

An essential aspect in the safe and reliable operation of a nuclear plant is the maintenance of the integrity of those barriers that contain the nuclear fuel and other radioactive material. Proper control of chemistry in plant fluid systems is important to this effort. Also important is the role chemistry can play in minimizing the build-up of radiation levels during plant operation. For these reasons, a review of plant chemistry is included in each evaluation visit.

E. Construction Project Evaluation Program

A new facet of INPO involvement in the nuclear power industry is the Construction Project Evaluation Program. This program was begun in February of 1982 as an initiative of the utility industry to improve the quality of construction and design control of nuclear power plants. Phase I of this program involves the development of performance objectives and criteria for the evaluations, the performance of three pilot evaluations by teams of experienced utility employees, and a self-initiated evaluation by each utility. Phase I is scheduled to be completed by December 31, 1982.

As of June 4, the program for Phase I is on schedule. The performance objectives and criteria have been developed and the first pilot has been completed. The schedule calls for the other two pilots to be completed by July 31. During August, the objectives and criteria will be revised to reflect lessons learned during the pilots. In early September, INPO will hold workshops to train utility personnel in conducting self-initiated evaluations. These evaluations will be conducted September through December of this year. Persons who were involved in the pilots will participate. INPO, using loaned utility personnel, will then make an assessment of the results of each utility's self-initiated evaluation. The direction for Phase II of the program will be determined later this year, after Phase I is further along.

This program has been guided by an ad hoc committee of 12 senior utility executives. This committee has been closely involved in criteria development and members of the committee are participating in the pilot evaluations.

The performance objectives and criteria that have been developed cover five areas of construction design as follows:

- organization and administration
- design control

- o construction control
- o project support
- o procurement control

While it is too early to predict the outcome of Phase I of the Construction Project Evaluation Program, the results to date have been encouraging. The performance objectives and criteria have received a favorable response. Results to date indicate that this type of evaluation program could benefit the utility industry and contribute to improved quality of nuclear plants under construction.

F. International Program

As INPO developed and expanded its activities during 1981, an International Program was formed to exchange operating experience and technical information with nuclear plant operators in other countries.

An accident or significantly deficient operation at a nuclear plant in any country affects all other plants. The Three Mile Island accident had considerable impact overseas. The majority of the world's operating plants are now outside the United States and the number of overseas plants is increasing. It is important that INPO's event analysis program has access to this growing data base. Additionally, no previously existing international organization has fostered direct interaction among the nuclear utilities actually engaged in and responsible for the operation of nuclear plants. The United States, through INPO, is now spearheading such an effort.

In 1981, two international participants joined INPO: Electricite' de France (EdF), the national utility in France, and Spain's TECNATOM, an electrical utility-owned service company based in Madrid. Each sent an experienced engineer on loan to INPO to act as liaison and to fill a staff position. Both are fully engaged in the technical work of the Institute. Toward the end of 1981, INPO's International Program was merged with that of the Nuclear Safety Analysis Center. In the combined International Program, INPO's focus on operational matters is complemented by NSAC's concentration on research.

Currently, INPO has twelve international participants as follows:

Electricite' de France (EdF), France
Radet for Karnkraftsakerhet (RKS), Sweden
Central Research Institute of Electric Power Industry (CRIEPI), Japan
Ontario Hydro (OH), Canada
Taiwan Power Company (TPC), Taiwan
Ente Nazionale per l'Energia Elettrica (ENEL), Italy
Tecnatom S.A., Spain
Comision Federal de Electricidad (CFE), Mexico
Furnas Centrais Electricas S.A., Brazil
Rheinisch-Westfalisches Elektrizitatswerk AG (RWE), West Germany
Central Electricity Generating Board (CEGB), England
Electronucleaire, Belgium

Nuclear power plants operated by these international participants total 105, with an additional 85 plants under construction. Adding the corresponding U.S. plants produces totals of 181 operating nuclear plants and 158 under construction worldwide. The collective experience from the operation of these plants is considerable; sharing that experience among all operators is important.

International participants contribute to the funding of INPO and NSAC so that the International Program is financially self-supporting. Participation is open to international organizations involved with the operation of nuclear power plants for the purpose of producing electricity. INPO encourages interested utilities to arrange for a common organization to act as the participant in each country, thereby conserving resources and simplifying information exchange with that country.

With the exception of on-site plant evaluations, international participants receive the same benefits as INPO's domestic members. These include, for example, participation in the SEE-IN program, participation in the NUCLEAR NOTEPAD computer conferencing network, and regular mailings of INPO publications. In addition, through working visits, technical information is exchanged in such areas as the evaluation process, operator training, and event analysis.

CONCLUSION

The activities of the Institute of Nuclear Power Operations that I have just described represent a unique and considerable effort by a U. S. industry to promote safety and reliability and to ensure the protection of industry employees and the public.

Over recent decades there has been an increasing involvement of government in the regulation and control of various U. S. industries. In my opinion, this has not always led to improved safety, reliability, and quality. It now appears that the Congress and the Administration are moving to reduce the involvement of government. I am pleased to be associated with an organization that could serve as an example of the kind of industry initiatives needed to allow a reduction in government control and regulation.

I am impressed by the insight of this committee and your evident determination to ensure a reliable supply of electricity for our country. As stated earlier, the Institute considers that efforts to improve safety and reliability are fully complementary. To that end, we pledge continued vigilance.

Thank you for allowing me to comment.

Biography

Zack T. Pate

Zack T. Pate is Vice President of Operations for the Atlanta-based Institute of Nuclear Power Operations (INPO).

Sponsored by the nuclear utility industry, INPO is an independent, non-profit organization dedicated to safety in nuclear power plant operations.

Dr. Pate is responsible for the three Institute's divisions that are directly concerned with nuclear plant operations--the Evaluation and Assistance Division, the Radiological Protection and Emergency Preparedness Division, and the Training and Education Division. He was previously the director of the Institute's Evaluation and Assistance Division.

Dr. Pate served in the U. S. Navy from 1958 to 1980. His assignments included chief engineer and commanding officer of nuclear-powered submarines. In the latter assignment, he was awarded a Legion of Merit. Following his command tour, Dr. Pate was deputy commander of a nuclear submarine squadron. He then served as special assistant to Admiral H. G. Rickover at the Naval Reactors Headquarters in Washington, D. C. His duties included providing oversight and guidance to the Navy's Operational Reactor Safeguards evaluation program for more than 100 nuclear power plants in submarines and surface ships.

Dr. Pate graduated from the U. S. Naval Academy in 1958. In 1970, he received a Ph.D. in nuclear engineering from the Massachusetts Institute of Technology.

Mr. FUQUA. Thank you very much, Dr. Pate.

Now we will hear from you, Dr. Patton. Without objection, your full statement will be included in the record.

STATEMENT OF DR. A. D. PATTON, ASSOCIATED POWER ANALYSTS, INC.

Dr. PATTON. Thank you, Mr. Chairman, ladies, and gentlemen.

I am A. D. Patton. Currently I am a principal and president of Associated Power Analysts, Inc., which is a consulting firm in the electric utility energy systems area, located in Bryan, Tex. I was formerly professor of electrical engineering at Texas A&M University and previously was an engineer in the electric utility engineering department of Westinghouse Electric Corp.

Since the early 1960's I have devoted a considerable portion of my career to development and application of quantitative methods for evaluating the reliability performance of electric utility systems.

Mr. FUQUA. Dr. Patton, before you get into your statement, I am afraid we are going to have to interrupt in the middle. We have another vote. We will have to run and vote, and we will come back and resume.

Dr. PATTON. Surely.

Mr. FUQUA. I apologize.

[Recess taken.]

Mr. FUQUA. Thank you, Dr. Patton. Please continue.

Dr. PATTON. Thank you, Mr. Chairman.

Mr. Chairman, with your permission, I would like to use the overhead projector and slides to outline the salient points of my testimony. Copies of the slides are attached.

My own experience is in the development and use of quantitative probabilistic methods for estimating the reliability performance of electric power systems. Therefore, I would like to discuss the use, misuse, and status of probabilistic reliability methods including desirable further research and development.

Probabilistic methods, or models, for estimating performance indices indicative of the reliability performance of electric power systems have been available for many years. The earliest models dealt with the adequacy of generating capacity while more recent models have provided methods for estimating the reliability performance of transmission and distribution systems. The use of probabilistic models in the planning and justification of projects has grown through the years since these models offer a means for quantifying the effects on system reliability of alternative courses of action. Properly used, quantitative reliability indices allow decisions influencing system reliability to be made on a sound and rational basis which should help utilities keep the cost of service and service reliability in proper balance.

It must be understood, however, that probabilistic models for estimating system reliability indices have tended to be rather idealized. That is, models have assumed simplified modes of operation which may differ markedly from actual operating conditions. The result of the simplifying and idealizing assumptions—made to facilitate calculations and reduce data requirements—is computed reliability indices which may differ appreciably from actual experience. This difficulty with most system reliability models is understood by power system reliability specialists who typically use computed reliability indices only in making relative comparisons of the reliability afforded by competing alternatives. It is reasoned that reliability indices, through inaccurate in an absolute sense, are still useful in relative comparisons. In recent years, however, there has been an increasing tendency and desire to view computed reliability indices as significant in an absolute sense. Obviously reliability indices which are significant and accurate in an absolute sense are more meaningful and useful than indices which have relative significance only. Unfortunately, there has also been a tendency to use traditional reliability models with their attendant simplifying assumptions to compute reliability indices in connection with such studies as:

(*a*) Determination of the economic optimum level of generation reserve in a system considering the cost to consumers of unserved energy;

(*b*) Evaluation of avoided cost associated with load management schemes or nonutility owned generation;

(*c*) Evaluations involving tradeoffs between production costs and capital costs in generation expansion alternatives;

(*d*) Evaluations of tradeoffs between expenditures in generation, transmission, and distribution.

Studies of this sort require accurate and absolutely significant reliability indices if they are to yield accurate conclusions.

All system reliability models are aggregated at some level of detail. That is, the methods do not explicitly model components and their operation beyond some level of detail but rather rely on the modeling of aggregated components through the use of appropriately gathered data. Such models are of course valid only so long as the data used to model an aggregated component are valid for the projected use of the aggregated component. A simple example is a transmission line which may be viewed as a single component for study purposes, but of course contains many parts such as towers, conductors, and insulators. The transmission line component is a valid representation only as long as the line's parts and their operating environment do not change and invalidate the line failure rate and other parameters attributed to the aggregated component. Therefore, care must be exercised in the use of reliability models and the data selected for use in them to be sure that both models and data are appropriate for the use intended. The danger always exists that aggregation in the models masks important effects.

[Slides 1-6 follow:]

ADVANTAGES OF PROBABILISTIC MODELS FOR SYSTEM RELIABILITY EVALUATION

- PROVIDE QUANTITATIVE MEASURES OF SYSTEM RELIABILITY PERFORMANCE

- RELIABILITY MEASURES OR INDICES RESPONSIVE TO DESIGN PARAMETERS

SLIDE 1

WEAKNESSES OF EXISTING MODELS

- MODELS ASSUME IDEALIZED CONDITIONS AND PRODUCE INDICES GENERALLY HAVING RELATIVE SIGNIFICANCE ONLY
- MODELS ARE AGGREGATED AND INCAUTIOUS USE OF AGGREGATED MODELS MAY RESULT IN INCORRECT CONCLUSIONS DUE TO THE MASKING OF IMPORTANT EFFECTS
- ACCURATE RESULTS REQUIRE ACCURATE INPUT DATA AND ACCURATE DATA IS OFTEN DIFFICULT TO OBTAIN

SLIDE 2

TENDENCY IS TOWARD GREATER USE OF PROBABILISTIC MODELS AND TOWARD USE OF THE MODELS IN STUDIES REQUIRING INDICES HAVING ABSOLUTE SIGNIFICANCE. SUCH STUDIES INCLUDE:

- DETERMINATION OF THE ECONOMIC OPTIMUM LEVEL OF GENERATION RESERVE IN A SYSTEM CONSIDERING THE COST TO CONSUMERS OF UNSERVED ENERGY;
- EVALUATION OF AVOIDED COST ASSOCIATED WITH LOAD MANAGEMENT SCHEMES OR NON-UTILITY OWNED GENERATION;
- EVALUATIONS INVOLVING TRADEOFFS BETWEEN PRODUCTION COSTS AND CAPITAL COSTS IN GENERATION EXPANSION ALTERNATIVES;
- EVALUATIONS OF TRADEOFFS BETWEEN EXPENDITURES IN GENERATION, TRANSMISSION, AND DISTRIBUTION.

SLIDE 3

RECENT AND CURRENT RESEARCH

1) ASSESSMENT, INTERPRETATION, AND EVALUATION OF SYSTEM RELIABILITY INDICES;

2) DEVELOPMENT OF IMPROVED METHODS FOR TRANSMISSION SYSTEM RELIABILITY DATA COLLECTION;

3) DEVELOPMENT OF COMPUTATIONALLY EFFICIENT METHODS FOR COMPUTING SYSTEM RELIABILITY INDICES IN LARGE-SCALE TRANSMISSION NETWORKS;

4) DEVELOPMENT OF MODELS FOR THE JOINT CONSIDERATION OF GENERATION AND TRANSMISSION IN SYSTEM RELIABILITY CALCULATIONS;

5) ASSESSMENT AND DEVELOPMENT OF MODELS CAPABLE OF CONSIDERING THE RELIABILITY IMPLICATIONS OF NEW ENERGY SOURCES SUCH AS SOLAR AND WIND GENERATION;

6) DEVELOPMENT OF MODELS CAPABLE OF REFLECTING UNIT AND SYSTEM OPERATING CONSIDERATIONS IN THE CALCULATION OF RELIABILITY INDICES IN GENERATING SYSTEMS.

SLIDE 4

NEEDED FUTURE RESEARCH

- INCORPORATE GREATER OPERATING REALITY IN PROBABILISTIC MODELS INCLUDING EFFECTS OF PROTECTIVE DEVICES AND RELAYING
- INCLUDE EFFECTS OF DEPENDENCIES AND COMMON-CAUSE FAILURES
- CONSIDER EFFECTS OF TRANSIENT UPSETS AS WELL AS STEADY-STATE DEFICIENCIES IN PROBABILISTIC MODELS
- VALIDATE ACCURACY OF PROBABILISTIC MODELS
- CONTINUE EFFORTS TO EXPAND AND IMPROVE EQUIPMENT RELIABILITY DATA COLLECTION SYSTEMS

SLIDE 5

RESULTS OF RECENT EPRI PROJECT ON GENERATING SYSTEM RELIABILITY EVALUATION

- UNIT AND SYSTEM OPERATING CONSIDERATIONS HAVE IMPORTANT INFLUENCES ON SYSTEM RELIABILITY AND MUST BE MODELED FOR ACCURATE RESULTS

- IMPORTANT OPERATING CONSIDERATIONS INCLUDE:

    1. UNIT STARTUP AND SHUTDOWN IN THE COURSE OF OPERATION TO SATISFY OPERATING RESERVE POLICIES AND UNIT COMMITMENT PRIORITIES AND RULES,

    2. UNPLANNED OUTAGE POSTPONABILITY AND THE MANAGEMENT OF POSTPONABLE OUTAGES,

    3. EXPLICIT MODELING OF UNIT STARTUP FAILURES DISTINCT FROM RUNNING FAILURES,

    4. UNIT STARTING TIMES.

- TRADITIONAL METHODS OF RELIABILITY MODELING WHICH DO NOT RECOGNIZE OPERATING CONSIDERATIONS APPEAR TO YIELD VERY PESSIMISTIC ESTIMATES OF SYSTEM RELIABILITY

- IMPROVED MODELS ARE NOW AVAILABLE

SLIDE 6

For example, if we just treat a generator as a black box, without any further discussion of the details of the black box, it may very well be that we are kidding ourselves. A man with his feet in the oven and his head in the icebox feels fine on the average, but is clearly in real trouble. Thus, inappropriate use of averages or overaggregation can be misleading. So that is the point I would like to leave with you there.

Accurate results certainly do require accurate input data, and accurate data are often difficult to obtain.

Regardless of the weaknesses of existing models, there is a very strong tendency these days to use probabilistic models in studies requiring, in fact, that the indices have absolute significance. Some examples include: Determination of the economic optimum level of generation reserve in a system considering the cost to consumers of unserved energy, a matter which I think has been addressed here perhaps earlier; evaluation of avoided costs associated with load management schemes or nonutility owned generation of whatever form; evaluations involving tradeoffs between production costs and capital costs in generation expansion alternatives; evaluation of tradeoffs between expenditures in generation, transmission, and distribution. All of these sorts of studies, I would suggest, require reliability indices which are generally not calculable accurately using existing models.

Recognizing that there are some difficulties and weaknesses, what are we trying to do about it? Let me briefly summarize some of the recent and current research in this area, which is hopefully making strides toward alleviating certain of the difficulties.

First, there has been work on the assessment, interpretation, and evaluation of system reliability indices. What indices are most meaningful for various purposes? What do they really mean as calculated? What can we use them for, and what should we not use them for?

Second, there is considerable work ongoing, and conducted in recent years, on development of improved methods for transmission system reliability data collection.

Third, there is work ongoing in development of computationally efficient methods for computing reliability indices in large-scale transmission networks which, from a computational point of view, is an extremely difficult problem, given the dimensionality of the problem and the physics of the problem.

Fourth, development of models for the joint consideration of generation and transmission in system reliability calculations. The existing models or the models that have been around heretofore generally have a hard time dealing accurately and effectively with trade offs—between generation and transmission.

Fifth, assessment and development of models capable of considering the reliability implications of new energy sources, such as solar and wind generation. There have been any number of studies made in which people try to model new technologies using old models that were never designed to be used for that purpose, and so you get answers which, if not wrong, are fortuitous.

Sixth, work has been recently completed on development of models capable of reflecting unit and system operating considerations in the calculation of reliability indices in generating systems. In fact, we just completed a piece of work for EPRI in that area, and I will have just a little bit more to say about that.

Some areas in which I see a need for further research in the future basically are to incorporate greater operating reality in probabilistic models, including effects of protective devices, relaying, and other factors. In other words, ladies and gentlemen, I think that we need to bring our models into closer correspondence with reality, particularly in view of the desire to use the reliability indices or measures computed by these models in manners which require that they have absolute significance. In fact, I think it is mandatory that we do this.

Certainly, also in this area, there is a need to include effects of various sorts of dependencies and common cause failures, because it is not just the odd random failure of a transmission line or a generator which causes a system to collapse. In fact, it is the joint or common mode collapse of a series or group of elements which causes real trouble. By and large, those kinds of failure modes have not been adequately treated in the models which exist today.

There is a need to consider effects of transient upsets as well as steady state deficiencies in probabilistic models. That is to say, a system may have plenty of installed generating capacity, but if it collapses every time you have a fault in the network somewhere, it is going to be terribly unreliable, and certainly NERC tries to address that area, as you heard Mr. Brown say.

But beyond simply being able to say that the system is able to withstand such events, we would like, in the final analysis, to be able to quantify those effects and to be able to say with some frequency or likelihood that the system will not be able to survive certain events, and so on.

Now, one area in which I have found a great lacking for a long time is proper validation of the accuracy of probabilistic models. People, including myself, have been developing models for years, and there has been relatively little work done on validation of those models against actual operating history—in other words, how well do they really replicate what is going on out there? I would simply suggest that if you do not validate models, you are very likely kidding yourself, because we are dealing with an extremely complex system, and accuracy of the model simply must be validated before we can have a great deal of confidence in it.

Certainly we need to continue our efforts to expand and improve equipment reliability data collection systems.

Let me just summarize for you a few of the conclusions of a recent EPRI project that we completed, which dealt with generating system reliability evaluation, but more specifically dealt with operating considerations within models for evaluating the reliability performance of generating systems.

Unit and system operating considerations have important influences on system reliability and must be modeled for accurate results. It may come as a surprise to you—or perhaps not—but the traditional models for evaluating the reliability of generating systems assume, in effect, that all the units are running all the time. Do they? Of course not. So right away a very serious question is raised.

If you assume that all the units are running all the time, what does "operating reserve" mean? It does not mean anything. What does "startup time" mean? It does not mean anything. What does the "rate of failure due to startups" mean? It does not mean anything.

In other words, we really need to bring at least a measure of the reality of operation into these models. Fortunately, we have been able to do some of that.

Important operating considerations include unit startup and shutdown in the course of operation to satisfy operating reserve policies and unit commitment priorities and rules.

Unplanned outage postponability in the management of postponable outages is a very important issue. You may or may not be aware that in the traditional calculations we have a definition of what constitutes a "forced outage" of a generating unit. There are lots of outages of generating units, some of which are forced and others of which are not forced, by definition. But in the models the typical use is to recognize that fraction of the outages which are termed "forced" and to use them in calculating the reliability performance and simply forget about all the other outages. The models then assume that the outages which are categorized as forced occur instantaneously and all the others that are not categorized as forced, in effect, never occur, so that we have made a huge simplifying assumption which may or may not be justified and which can have tremendous impacts if the degree of postponability of outages happens to change, as it probably will, as you change the mix of units—nuclear and the like. So the detailed treatment of unplanned outage postponability has simply been aggregated away in the traditional models, and you simply may be ignoring a problem, we would suggest. Anyway, it is certainly an issue which needs to be addressed in an up-front way.

We feel that there is a need to explicitly model unit startup failures as distinct from unit running failures. The impacts of these two modes of failure are functions of unit duty cycle. That is, how often you start the unit and how long you run it, once it is started.

Unit starting times are certainly important. If it takes you a month to bring a unit on line as opposed to a minute, there ought to be a difference in the reliability credit given that unit. In the traditional models there is no explicit mechanism for that, but fortunately there is now.

Traditional methods of reliability modeling which do not recognize these operating considerations together with others appear to us to yield very pessimistic estimates of system reliability, and in fact the relationship that these traditional indices bear to reality is not fixed, and so we have found in certain typical systems that they may be off by a factor of 20. In other typical systems they may be off by a factor of 5. Who knows what ratio they are off in the system under study in your case.

So, if you are going to try to use these indices in an absolute manner, then you had better be very careful. Some improved models are now available. Certainly they are not perfect; as I have suggested, there is a need for ongoing research in this area.

Thank you.

[The prepared statement of Dr. Patton follows:]

Testimony Before

Subcommittee on Energy Development & Applications
Subcommittee on Energy Research & Production

By

A. D. Patton
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Washington, D.C.

June 10, 1982

A. D. PATTON

Dr. A. D. Patton is President of Associated Power Analysts, Inc., Bryan, Texas. He was associated with the Electric Utility Engineering Department of the Westinghouse Electric Corp. from 1957 - 1965 and was Professor of Electrical Engineering at Texas A&M University from 1965 - 1979. Dr. Patton received the B.S.E.E. degree from the University of Texas at Austin, the M.S.E.E. from the University of Pittsburgh, and the Ph.D. from Texas A&M University. He is a Registered Professional Engineer in the State of Texas and is a Fellow of the Institute of Electrical & Electronics Engineers.

Dr. Patton's consulting and research work has been concentrated on the development and application of quantitative methods for evaluating the reliability of electric power systems, the collection and analysis of equipment failure data and the development and analysis of reliability criteria. He is the author of a large number of papers and technical reports in this area of work. He has led major research efforts for both the U.S. Department of Energy and the Electric Power Research Institute and has provided consulting services for a variety of utility, industrial, and legal clients.

Probabilistic Methods for Estimating the Reliability Performance of Electric Power Systems

Probabilistic methods, or models, for estimating performance indices indicative of the reliability performance of electric power systems have been available for many years. The earliest models dealt with the adequacy of generating capacity while more recent models have provided methods for estimating the reliability performance of transmission and distribution systems. The use of probabilistic models in the planning and justification of projects has grown through the years since these models offer a means for quantifying the effects on system reliability of alternative courses of action. Properly used, quantitative reliability indices allow decisions influencing system reliability to be made on a sound and rational basis which should help utilities keep the cost of service and service reliability in proper balance.

It must be understood, however, that probabilistic models for estimating system reliability indices have tended to be rather idealized. That is, models have assumed simplified modes of operation which may differ markedly from actual operating conditions. The result of the simplifying and idealizing assumptions (made to facilitate calculations and reduce data requirements) is computed reliability indices which may differ appreciably from actual experience. This difficulty with most system reliability models is understood by power system reliability specialists who typically use computed reliability indices only in making relative comparisons of the reliability afforded by competing alternatives. It is reasoned that reliability indices, though inaccurate in an absolute sense, are still useful in relative comparisons. In recent years, however, there has been an increasing tendency and desire to view computed reliability indices as significant in an absolute sense. Obviously reliability indices which are significant and accurate in an absolute sense are more meaningful and useful than indices which have relative significance only. Unfortunately, there has also been a tendency to use "traditional" reliability models with their attendant simplifying assumptions to compute reliability indices in connection with such studies as:

a) determination of the economic optimum level of generation reserve in a system considering the cost to consumers of unserved energy;

b) evaluation of avoided cost associated with load management schemes or non-utility owned generation;

c) evaluations involving tradeoffs between production costs and capital costs in generation expansion alternatives;

d) evaluations of tradeoffs between expenditures in generation, transmission, and distribution.

Studies of this sort require accurate and absolutely significant reliability indices if they are to yield accurate conclusions.

All system reliability models are aggregated at some level of detail. That is, the methods do not explicitly model components and their operation beyond some level of detail but rather rely on the modeling of aggregated components through the use of appropriately gathered data. Such models are of course valid only so long as the data used to model an aggregated component are valid for the projected use of the aggregated component. (A simple example is a transmission line which may be viewed as a single "component" for study purposes, but of course contains many parts such as towers, conductors, and insulators. The transmission line "component" is a valid representation only as long as the line's parts and their operating environment do not change and invalidate the line failure rate and other parameters attributed to the aggregated component.) Therefore, care must be exercised in the use of reliability models and the data selected for use in them to be sure that both models and data are appropriate for the use intended. The danger always exists that aggregation in the models masks important effects.

All probabilistic reliability models require various pieces of numerical data such as equipment failure rates and repair times. Thus clearly the accuracy of computed reliability indices is highly dependent on the availability of accurate data for input to the reliability models. Data accuracy becomes particularly important when system reliability indices having absolute significance are required.

The electric utility industry is generally aware of the shortcomings and deficiencies of existing probabilistic models for computing system reliability indices and EPRI and DOE have supported, and are supporting, research work aimed at improving the accuracy, generality, and computational efficiency of models and the data required by them. Recent and current research includes:

1) assessment, interpretation, and evaluation of system reliability indices;
2) development of improved methods for transmission system reliability data collection;
3) development of computationally efficient methods for computing system reliability indices in large-scale transmission networks;
4) development of models for the joint consideration of generation and transmission in system reliability calculations;
5) assessment and development of models capable of considering the reliability implications of new energy sources such as solar and wind generation;
6) development of models capable of reflecting unit and system operating considerations in the calculation of reliability indices in generating systems.

These research efforts have produced a number of models, methods, and concepts which promise to improve the accuracy, appropriateness, and speed of system reliability calculations. Some of this work is immediately useful and should soon pass into practical use while other work provides a point of departure for further needed research.

Areas in which further or continuing research are believed to be needed are summarized as follows.

1) A need exists to incorporate greater operating reality in probabilistic models for study of all portions of the power system. This would tend to make the models more directly responsive to planning and operating issues and would produce more accurate, physically meaningful, reliability

indices which would have significance in an absolute sense. Operating issues which should be recognized include unit duty cycles and unit dependencies arising from the mode of unit or system operation or the environment. Presently, probabilistic reliability calculations reflect steady-state system conditions only but since many large-scale system collapses are due to transient upsets rather than steady-state deficiencies it follows that system reliability indices should reflect transient as well as steady-state events. A need also exists to better reflect the effects of protective device and relay operations and their failures in system reliability modeling. Indeed the accurate modeling of protective device and relaying effects is believed to hold the key to calculations of the frequency of large-scale system collapses as such collapses are usually due to protective device or relaying problems.

2) In concert with the model improvement efforts suggested in (1), major efforts need to be made to validate the accuracy of the mathematical models. Unvalidated model accuracy improvements are likely to prove to be illusions given the complexities of power systems.

3) Efforts to expand and improve equipment reliability data collection systems should be continued. Accurate data is a prerequisite to accurate system reliability index calculations.

Associated Power Analysts, Inc. has recently completed development of several new generating system reliability models for EPRI under contract RP 1534-1, "Modeling of Unit Operating Considerations in Generating Capacity Reliability Evaluation". These new models relax many of the simplifying assumptions of traditional models and produce reliability indices of greater accuracy and physical significance. The executive summary of the final report of the contract is attached.

SUMMARY OF EPRI
PROJECT RP 1534-1

MOTIVATION

Existing methods for calculating reliability indices for use in evaluation and assessing the reliability performance of generating systems are idealized and do not explicitly consider many unit and system operating considerations which influence system reliability. Thus, existing reliability models offer no means for accurately evaluating alternatives which differ in terms of unit or system operation. Further, reliability indices produced using existing models may differ appreciably from actual experience and are therefore primarily useful only for making relative comparisons of the reliability afforded by alternatives and not in analyses requiring indices which are physically significant and accurate in an absolute sense.

The deficiencies and shortcomings of existing models have provided the motivation for the present project on the development of reliability models which explicitly recognize unit and system operating considerations. The present project continues and extends work begun under EPRI TPS 77-719, "Effect of Operating Considerations on Reliability Indices Used For Generation Planning", and U.S. Department of Energy Contract EC-77-S-01-5104, "Large-Scale System Effectiveness Analysis". Here work was begun on the Monte Carlo simulation and analytical models which have been further developed, tested, and brought to a point of practical application under this project.

OBJECTIVES AND APPROACH

The general objective of the project was the development of models which explicitly recognize operating considerations in the calculation of reliability indices in generating systems. The project scope was limited to single-area systems with conventional non-energy-limited generation.

Specific project objectives and the approaches for their attainment are summarized as follows.

1. Identify unit and system operating considerations which influence generating system reliability performance. Issues, factors, constraints, and considerations which influence system reliability, and which have not traditionally been included in reliability models,

were identified through discussions with utility planners and operators and through experience with the earlier EPRI and DOE projects. Here the intent was to determine the physical processes or operating considerations which must be modeled if system reliability indices are to be accurately calculated.

2. Improve and validate the accuracy of the GENESIS Monte Carlo simulation model. Work on a detailed Monte Carlo simulation model called GENESIS was begun under the earlier EPRI and DOE projects. This model was improved and modified to reflect additional operating considerations as identified above. The accuracy of the GENESIS model was then tested using the Public Service Electric and Gas Company and Pennsylvania-New Jersey-Maryland Interconnection systems and historical data from these systems.

3. Conduct sensitivity studies of synthetic systems. The GENESIS model was used to study the effects of modeling various operating considerations on synthetic systems possessing a wide range of characteristics. Here the intent was to determine which operating conditions should be modeled in reliability studies. Further, the results of the Monte Carlo simulation studies were used as "benchmarks" to evaluate the accuracy of reliability indices calculated using the analytical models also under development.

4. Develop analytical methods capable of explicitly modeling operating considerations. Four basic modeling approaches called the OPCON model, the OPPLAN model, the total-Markov model, and the analytic simulation model were investigated and evaluated through studies on synthetic systems. Ultimately, two models, the OPCON model and the OPPLAN model, were chosen for detailed development and testing based on their accuracies and computational efficiencies.

5. Illustrate the application and accuracy of the new models using synthetic systems. The GENESIS, OPCON, and OPPLAN models were used to study a range of synthetic systems. Reliability indices computed using the new models were compared. Further, reliability indices obtained using the new models were compared with the results of the "traditional" generation reliability model which does not recognize operating considerations.

6. Identify potential applications of the new models. Potential applications in the areas of long-range and operations planning were identified through discussions with utility planners and operators.

7. Identify data requirements of new models. The fundamental data requirements of the new models were identified through investigations of field data and data collection systems. Recommendations for improvements of existing data collection systems and standards to accommodate the requirements of the new models were made.

CONCLUSIONS AND DELIVERABLES

A number of unit and system operating considerations have important influences on system reliability and must be modeled for accurate reliability index calculation. The most important of these operating considerations are:

1. unit startup and shutdown in the course of operation to satisfy operating reserve policies and unit commitment priorities and rules,
2. unplanned outage postponability and the management of postponable outages,
3. explicit modeling of unit startup failures distinct from running failures,
4. unit starting times.

Traditional methods of calculating system reliability indices which do not recognize these operating considerations appear to yield very pessimistic estimates of system reliability. However, it is also recognized that some methods do presently exist which are capable of considering unit duty cycles in a historical sense through use of unit forced outage rates which more closely estimate the probabilities of unit outages during periods of need. The accuracy of such models is undoubtedly superior to that of so-called traditional models as long as historically-observed unit duty cycles remain appropriate for systems which are to be studied. A major shortcoming of even these improved models is, then, that they do not explicitly model operating considerations and thus cannot reflect changes in unit or system operation.

The new analytical and Monte Carlo simulation models which have been developed are capable of explicitly recognizing the above important operating considerations as well as other issues. Therefore, the new models should be particularly useful in studying alternatives which differ in their modes of unit or system operation. The accuracy of the new models for use in studying systems on a single-area basis was demonstrated using historical data from two actual systems.

The GENESIS Monte Carlo simulation model and the OPCON and OPPLAN analytical models have been implemented in prototype-grade computer programs which are available for use. All programs are computationally attractive for use on generating systems of any practical size.

The data required by the new models is more extensive than that required for traditional models, but is generally available from existing data collection systems. However, certain minor changes in ANSI/IEEE Standard 762 and the NERC/GADS data collection system would improve the ability to provide the data needed in the new models.

POTENTIAL APPLICATIONS

The new models explicitly recognize and consider a number of unit parameters and characteristics as well as unit and system operating considerations which influence system reliability performance. Thus, the most important general area of application of the new models is expected to be in evaluation of alternatives which differ in those characteristics and operating considerations. Additionally, it is expected that the new models will produce reliability indices which are much closer to field experience than those produced by traditional models. Thus, the new models should find application where it is important that indices be physically meaningful and accurate in an absolute sense.

Potential applications of the new models fall into the general areas of long-range planning and operations planning. Some examples of potential applications in these areas are summarized as follows.

Long-range planning:

1. Investigate effects of change in unit mix.
2. Investigate effects of changes in unit operating characteristics.
3. Evaluate effects of changes in unit failure rates associated with changes in duty cycle.
4. Investigate effects of changes in load cycle shape.
5. Improve estimates of production costs.
6. Evaluate tradeoffs between operating and capital costs.
7. Estimate avoided costs associated with load management or consumer-owned or unconventional generation.
8. Investigate proper level of capacity reserve.

Operational planning:

1. Evaluate spinning reserve policy.
2. Evaluate unit commitment policies and rules.
3. Evaluate spare parts inventories and speed of repair.
4. Evaluate alternative planned outage schedules.

Mr. FUQUA. Thank you, Dr. Patton.

Now we will hear from you, Mr. Kerner Smith. Without objection, your statement will be included in the record.

STATEMENT OF H. KERNER SMITH, MANAGER, BOILERS AND COMPONENTS, FOSSIL POWER GENERATION DIVISION, BABCOCK & WILCOX CO., ACCOMPANIED BY SAM ESLEEK, RESEARCH LIASION DEPARTMENT

Mr. SMITH. Thank you, Mr. Chairman.

We are pleased to have the opportunity to discuss reliability and availability of steam generation equipment supplied and serviced by Babcock & Wilcox to the U.S. electric utilities.

With your permission, I will use some slides, and Mr. Sam Esleek from our research liaison department will operate the machine for me.

For well over 100 years B&W has been the leading supplier of coal-fired steam systems to electric utilities and industrial users of steam. B&W has been known as a pioneer in fossil steam systems, and we supply complete systems, including fuel preparation and air pollution control systems, as well as the boilers, such as this one shown, which is a 400-megawatt lignite-fired unit in Texas. [Slide shown.]

Just a side comment—of course the heart of this plant is the boiler, and the boiler is about as large as a 30-storey building and consumes approximately 2 million tons of coal per year.

The company is heavily involved in all aspects of reliability and availability improvement for fossil fuel steam systems. For purposes of this discussion, the fossil fuels of interest are coal, including lignite; oil; and gas.

While oil and gas supply a major portion of existing power source requirements, coal will be the principal fuel for new power sources and has been the choice for new utilities steam generation systems purchased in the last decade.

Many oil- and gas-fired boilers were purchased by utilities in the 1950's and 1960's and therefore do represent a part of the backbone of the electric power supply. Since oil and gas are low-ash fuels, furnace design was governed by limits of heat liberation. Tube metal temperature limits were set considering the ability to cool the tubes by the water and/or steam mixtures therein.

Little information was available back then about fuel-ash corrosion, internal oxidation of tubes, effect of thermal stress due to frequent startup and shutdown or limits of practicality of pressure, temperature, and plant size.

A typical oil-fired design of the 1960's is shown here. [Slide shown.] Operating availability of these units varies considerably, with some units achieving availability in the mid-1990's percentile. Other units have average availabilities in the mid-1970's during the first 5 to 10 years of operation, and then dropping subsequently if a well-planned maintenance program is not utilized.

Modern technology has been applied to some of these older boilers in order to increase availability and maximum dependable rating as well. For example, the boiler shown previously was refurbished and converted to a modern design, as shown here [slide shown] in 1979, and boiler-equivalent availability was improved to approximately 98 percent over the first 18 months of operation.

In the early 1960's the largest coal-fired boiler on order from B&W was a 450-megawatt unit. In 1963, the first 600-megawatt units were ordered, and then in 1967, the first 1,300-megawatt unit.

It took the industry 75 years to reach the 200-megawatt size level and in only one decade to escalate from that size up to 1,300 megawatts.

In contrast with oil- and gas-fired boilers, the coal ash characteristics are the governing criteria which set the furnace design and generally coal-fired units become considerably larger in frame size as the coal quality deteriorates.

Selection of proper boiler design depends upon the ability to evaluate the important characteristics of the coal and coal ash, particularly the slagging and fouling characteristics.

Nearly half of the coal-fired units in the 1960's were in the 500- to 700-megawatt size unit and were designed for baseload and supercritical steam conditions with reheat to 1,005-degree steam temperature burning eastern bituminous coals.

Several occurrences in the early 1970's had a significant effect on boiler design. First, nuclear units were expected to handle the future baseload capability, with fossil units to be used primarily for cycling service. It was generally believed that drum-type boilers were better suited for cycling operation than supercritical designs. Many of the early once-through boilers are cyclone-fired, burning very high-ash, poor quality fuels. The lower availability achieved for these and the need for cycling precipitated a strong trend to drum-type designs.

Second, the 1972 Federal New Source Performance Standards established emission limits for NO_X and SO_2 and particulates. While the limits on particulates did not directly affect the boiler design, the limits on NO_X and SO_2 significantly affected boiler design.

There was and remains a significant trend toward western coals, which generally possess a more difficult coal ash characteristic. This is shown on the next slide. [Slide shown.]

As can be seen, prior to 1970, most units were designed for eastern bituminous coal. A comparison of 1960's vintage 800-megawatt boiler is shown on the next slide, next to a 500-megawatt nominal size for several of the coals utilized today. The 800-megawatt 1960's design is the one on the far left. [Slide shown.]

The bituminous coals utilized today, as well as the western coals, exhibit greater slagging and fouling tendencies and are often more abrasive to the fuel preparation equipment and the internal tube banks themselves. It is not surprising therefore to see operating availability of boilers designed for better coals in the 1960's begin falling off as these fuel effects are encountered. The higher ash loadings and lower ash fusion temperatures require methods to reduce the furnace exit temperature to control slagging and fouling and lower velocities of the ash through the tube banks to control erosion.

Fortunately there is excellent experience available with many post-1970 B&W boilers handling these lower grade fuels, so that design approaches may be applied to improve availability of the 1960's vintage units, as required through engineered upgrades.

The cost of upgrading to today's technology are small in comparison to the incremental capacity and equivalent availability gains.

With increasing fuel costs, more boilers that fire a wide range of fuels and emphasis on availability, today's boiler operators require comprehensive diagnostic information to achieve cost-effective operation. With state-of-the-art computer systems, continuous analytical monitoring of boiler performance is now technically and economically practical.

B&W has developed a diagnostic system shown on the next slide that uses a time-proven computer boiler model. The boiler model can continuously analyze performance, provide the operator with an indication of surface cleanliness, optimize efficiency and/or heat rate. This helps eliminate much of the subjectivity in operator performance. Such a system can collect data from the boiler, check it for accuracy, interpret it using the basic laws of thermodynamics, and reduce it to quantitative information. [Slide shown.]

This information provides the operator significant guidance in improving availability.

A supercritical boiler designed in 1965 and burning eastern coal was recently evaluated for capacity, availability, and efficiency. This evaluation utilized an on-site real-time computerized boiler model. The model enabled capacity to be increased 4 to 8 percent—15 to 30 megawatts—and statistical availability improved 1 percent, or 3.5 days a year. Efficiency was maintained.

Significant enhancements are planned for this diagnostic equipment.

The reliability of powerplant equipment depends a great deal on the operating care and the quality of maintenance provided. Also, the deterioration of boiler equipment referred to as "aging" is largely dependent upon the fuel being fired. Coal-fired units vary widely, but compared to gas- and oil-fired units they are generally less reliable and require significantly more maintenance owing to the effects of coal slag and ash.

Generally, the boiler availability decreases with age, as shown here [slide shown], which is representative of a sample of B&W units.

The metal deterioration is gradual and very difficult to evaluate; because powerplant operators cannot readily identify the condition of the metal without putting it into a metallurgical laboratory, most maintenance work is not initiated until the part completely fails. This is referred to in the industry as ".breakdown maintenance."

Service programs B&W now provides to address the long-term life cycle maintenance are boiler fitness surveys, manage-maintenance concepts, and operator maintenance training programs.

A boiler fitness survey is a thorough examination of the boiler and related equipment to ascertain the condition of the material. It is initiated by a close visual examination to identify areas where more exacting tests may be required. These additional tests may be in the form of ultrasonic metal thickness readings, radiography, or sampling for visual and/or micrographic metallurgical examination, as shown on this slide. [Slide shown.]

With detailed time-history knowledge of the material's condition, an economic evaluation can be made to determine the extent and timing of maintenance and rehabilitation programs, thus leading to predictive management of maintenance programs.

The following slides represent conditions normally found today in coal-fired boilers. You can see the effects of erosion of temperature at thermal stress and long-term effects on tubes are readily apparent in looking at these slides. [Slides shown.]

Boiler fitness studies can also indicate areas where engineered upgrades are appropriate to restore original availability.

A manage-maintenance program is a comprehensive plan to identify maintenance life cycles on a component by component basis and to develop preventive maintenance programs that preclude breakdown maintenance and which can be justified economically.

Manage-maintenance can maintain boiler availability near the original levels, as shown on this slide. [Slide shown.]

These programs take into consideration the operating experiences, design arrangements, boiler fitness surveys, downtime maintenance, productivity, downtime costs and quality control, and technologic advances which are known by the boiler manufacturer. The ultimate in execution is to compress all maintenance requirements into short scheduled outage with absolute quality so that subsequent shutdowns are not required for associated repairs.

Reliability depends upon proper maintenance and proper operation. In both areas quality training is necessary in order to execute assignments properly.

B&W is now providing videotape training programs for operators and maintenance personnel and simulators, as shown on the next slide. [Slide shown.]

These are computerized real models of how the boiler behaves, which can be utilized far in advance of the plant going into operation.

In the past 20 years the average size unit purchased by the U.S. utilities has increased from 225 megawatts to 600 megawatts, and the largest are 1,300-megawatt-size units. The questions of economies of scale, plant heat rate, and relative availability are factors considered by each utility in determining the size of the unit required for their particular system. There has been much debate on the merits of smaller versus larger boiler units.

It has been well documented that there is a significant savings in capital investment and in net plant heat rate as unit sizes increase. A review of NERC availability data for the latest 10-year period shows that plant availability falls off significantly as unit size increases, as shown on the next slide. [Slide shown.]

These data indicate a deterioration of almost 6 percent in boiler availability when comparing units in the 200-megawatt range with those in excess of 600 megawatts.

We believe this presentation may be misleading to those who wish to conclude that this is a size effect. As a boiler manufacturer, we have not seen this occur when we analyzed data on our modern boilers. As an example, NERC data on the last 10 B&W supercritical units put in service since 1973 show an average availability of 87 percent, which compares favorably to the results obtained from boilers in the 200-megawatt-size range, although the average size for these units is much greater in the 800-megawatt range.

Many units exceed this average, as indicated on the next slide by the excellent availability of the very large, 1,300-megawatt-units for American Electric Power. These are the largest boiler units in the world. [Slide shown.]

A further analysis of availability data comparing our most recently 24-pound drum boilers with supercritical boilers shows no appreciable difference in average cumulative availability, as indicated on the next slide. [Slide shown.]

We conclude then that the modern coal-fired steam generators are capable of achieving high availability regardless of cycle or size; system requirements, first costs, and plant efficiency then should be the criteria for determining each utility's size selection.

Further evidence of technological improvement is shown on the next slide. [Slide shown.]

These boiler units average 875 megawatts and total 188 years of operating experience. Note that the 5 most recent units show an availability 5 percentage points greater than the average for all 22 units. It is our opinion that part or all of this differential could be recovered for the older units through upgrading and modification to today's designs.

Finally, B&W believes that a target availability of 92 percent can be achieved on a modern coal-fired boiler, and since the boiler is a governing factor in determining plant availability, this target is an important one in consideration of your objectives.

The other major components must also be addressed in a systems analysis fashion in order to make a judgment on overall plant availability targets. We are performing such services as the industry desires.

As stated earlier, older units can often benefit from today's technology of design and from modern methods of inspection analysis and maintenance management. The key to improved availability of these units is the financial health of the utility industry, which must be able to justify such improvements in terms of return on invested capital or in pay-back of maintenance budgets and be able to afford to make the move to do this work.

Thank you again for the opportunity to discuss this with you today.

[The prepared statement, plus exhibits 1–20 follow:]

Statement of

Mr. H. Kerner Smith

Manager, Boilers and Components
Fossil Power Generation Division

Before the Sub-Committees on Energy Development and Applications and Energy Research and Production of the Science and Technology Committee, U.S. House of Representatives

June 10, 1982

Babcock & Wilcox
a McDermott company

TESTIMONY

BEFORE U.S. HOUSE OF REPRESENTATIVES

SCIENCE AND TECHNOLOGY COMMITTEE

H. KERNER SMITH

BABCOCK & WILCOX

UNIT OF MC DERMOTT, INCORPORATED

RELIABILITY OF UTILITY STEAM GENERATION SYSTEMS

Mr. Chairman and distinguished members of the Sub-Committee, I am Kerner Smith, Manager of Boilers and Components for the Fossil Power Generation Division of Babcock and Wilcox. I am pleased to have the opportunity to discuss reliability and availability of steam generation equipment supplied and serviced by Babcock and Wilcox to U.S. electric utilities. Babcock and Wilcox has provided leadership in applications of steam generation since 1867. Our boilers powered Thomas Edison's lab, and most of our Country's naval and merchant vessels. The Company is the leading supplier of coal-fired steam systems to electric utilities and industrial users of steam. B&W has been known as a pioneer in fossil steam systems and supplies complete systems including fuel preparation and air pollution control systems as shown in Exhibit 1, a 400 MW station in Texas. Some current significant commercialization efforts being made to promote the use of coal include the development of advanced pulverized coal-fired boilers, direct ignition of pulverized coal, high solids coal-water slurries, wet and dry SO_2 scrubber development and atmospheric fluidized bed boiler development. The Company is heavily involved in all aspects of reliability and availability improvement for fossil fuel steam systems.

For purposes of this discussion, the fossil fuels of interest are coal, oil and gas. While oil and gas supply a major portion of existing power source requirements, coal will be the principal fuel for new power sources, and has been the choice for new utility steam generation systems purchased in the last decade.

OIL AND GAS FIRED BOILERS

Many oil and gas fired boilers were purchased by utilities in the 1950's and 60's. During this time period, the largest oil and gas fired boilers were in the 600 MW size range and the rapid escalation of unit size from the 1950's (where the average size was less than 200 MW's) to the latter 60's was accompanied by industry trends to higher efficiency and lower capital cost designs. Since oil and gas are low ash fuels, furnace design was governed by limits of heat liberation. Tube metal temperature limits were set considering the ability to cool tubes by the water and/or steam mixtures therein. Little information was available about fuel ash corrosion, internal oxidation of tubes, effect of thermal stress due to frequent start-up, and shutdown, or limits of practicality of pressure, temperature and plant size. A typical oil-fired design of the 1960's is shown on Exhibit 2. Operating availability of these units vary considerably with some units achieving availability in the mid-90's percentile. Other units have average availabilities in the mid-70's during the first 5-10 years of operation, and then dropping subsequently if a well planned maintenance program is not utilized. Modern technology has been applied to some of these older boilers in order to increase availability, and maximum dependable rating. For example, the boiler shown in Exhibit 2 was refurbished and converted to a modern design in 1979 and boiler equivalent availability was improved to approximately 98% over the first eighteen months of operation.[1]

COAL FIRED BOILERS

As with oil-fired boilers, there was a very rapid increase in unit capacity during the 1960's. In the early 60's, the largest coal-fired boiler on order from B&W was the 450 MW unit for Ohio Power's Sporn Plant. In 1963 the first 600 MW units were ordered for Ohio Power/Buckeye Power's Cardinal Plant and in 1967 the first 1300 MW unit was ordered by the Tennessee Valley Authority.

In contrast with oil and gas-fired boilers, the coal ash characteristics are the governing criteria which set the furnace design and, generally, coal-fired units become considerably larger in frame size as the coal quality deteriorates. Selection of proper boiler design depends upon the ability to evaluate the important characteristics of the coal and coal ash, particularly the slagging and fouling characteristics.

During the 1960's, the majority of boilers were designed to burn Eastern Bituminous coals. Neary half of the coal-fired units of the 1960's were in the 500-700 MW size range and were designed for base load and advanced steam conditions of 3500 psi and 1005F superheated steam with reheat to 1005F.

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[1] "Jacksonville Electric Authority's Spiral Furnace Retrofit Operating Experience", Chapman, H.W., Clessuras, G.J., and Orender, H.C., American Power Conference Proceedings, April 1982.

Several occurrences in the early 70's had a significant effect on boiler designs.

First, nuclear units were expected to handle future base load capacity, with fossil units to be used primarily for cycling service. It was generally believed that drum type boilers were better suited for cycling operation than once-through designs. Many of the early once-thru boilers are cyclone fired, burning high ash poor quality fuels. The lower availability achieved for these once-through designs precipitated a strong trend to drum type designs.[2]

Second, the 1972 Federal New Source Performance Standards (NSPS) established emission limits for NO_x and SO_2 and particulates. While the limits on particulates did not directly affect the boiler design, the limits on NO_x and SO_2 significantly affected boiler design.

There were large reserves of low sulfur coal in the Western states and it was generally more attractive to use low sulfur coal than to apply wet scrubbers which at that time had limited operating experience. Hence, there was and remains a significant trend toward Western coals (Exhibit 3) which generally possess a more difficult coal ash characteristic than Eastern coals and require more conservative designs. A comparison of a 60's vintage 800 MW.

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[2] Ten Years Experience with Large Pulverized Coal-Fired Boilers for Utility Service, Smith, H.K., Bouton, G.W., and Haller, H.K., American Power Conference, April 1982.

boiler is shown in Exhibit 4 next to a 500 MW nominal size for several of the coals utilized today. The bituminous coals utilized today, as well as the Western coals exhibit greater slagging and fouling tendencies and are often more abrasive to the fuel preparation equipment and the internal tube banks themselves. It is not surprising, therefore, to see operating availability of boilers designed for better coals in the 60's begin falling off as these fuel effects are encountered - the higher ash loadings and lower ash fusion temperatures require methods to reduce furnace exit temperatures to control slagging and fouling, and lower velocities of the ash through the tube banks to control erosion.

Fortunately, there is excellent experience available with many post-1970 B&W boilers handling these lower grade fuels so that design approaches may be applied to improve availability of the 60's vintage units as required through engineered upgrades. This has been demonstrated on several units and reported to industry committees. The costs of upgrading to today's technology are small in comparison to the incremental capacity and equivalent availability gains.

ENHANCEMENT OF BOILER AVAILABILITY WITH PERFORMANCE DIAGNOSTICS

With increasing fuel costs, more boilers that fire a wide range of fuels, and emphasis on availability, today's boiler operators require comprehensive diagnostic information to achieve cost-effective operation.

The typical power plant data acquisition system, however, does little more than evaluate data on a point-by-point basis.

With state-of-the-art computer systems, continuous analytical monitoring of boiler performance is now technically and economically practical.

Babcock & Wilcox has developed a diagnostic system that uses a time-proven comprehensive computer boiler model (Exhibit 5). The boiler model can continuously analyze boiler performance, provide the operator with a quantitative indication of surface cleanliness, optimize efficiency and/or heat rate and directly provide priorities to the sootblower control system.

A boiler diagnostic system dedicated to analytical data processing helps eliminate much of the subjectivity in operator performance. Such a system can collect data from the boiler, check it for accuracy, interpret it using the basic laws of thermodynamics, and reduce it to quantitative information. This information provides the operator significant guidance in improving availability.

A 3500 psi cycle boiler designed to 1965 Standards and Eastern fuel (coal) was recently evaluated for capacity, availability, and efficiency. This evaluation utilized an on-site, real time, computerized boiler model. The model indicated that capacity could be increased 4%-8% (15 MW-30 MW), statistical availability improved 1% (3.5 day/yr.) and efficiency could be maintained. Significant enhancements are planned for this diagnostic equipment to extend its capabilities to evaluate stress on boiler parts.

MANAGED MAINTENANCE PROGRAMS AND BOILER FITNESS STUDIES

The reliability of power plant equipment depends a great deal on the operating care and the quality of maintenance provided. Also, the deterioration of boiler equipment (referred to as aging) is largely dependent upon the fuel being fir- Natural gas fired units have the highest reliabilty and the least maintenance; coal fired units vary widely, but compared to gas and oil fired units, they are generally less reliable and require significantly more maintenance owing to the effects of coal slag and ash. Generally, the boiler availability decreases with age as shown on Exhibit 6 which is representative of a sample of B&W units.

Maintenance cycles for power plant equipment cover several years. The metal deterioration is gradual and difficult to evaluate. Because power plant operators cannot readily identify the condition of the metal without putting it into a metallurgical laboratory, most maintenance work is not initiated until the part completely fails. This is referred to as "breakdown maintenance," and may catch the operator without adequate spare parts or skilled labor to make quick and efficient repairs. At this point, however, operators can start to establish some life expectancies and be prepared for subsequent failures. But by the time the part is about to fail again (several years later), the person or persons who knew the life expectancy may have left the plant. Obviously, the breakdown maintenance occurs again. As equipment suppliers, we want to make the tools available to restore availability and then maintain it at the level achieved in the early years.

Service programs Babcock & Wilcox provides to address the long-term life cycle maintenance are (1) boiler fitness surveys, (2) managed maintenance concepts, and (3) operator and maintenance training programs.

Boiler Fitness Surveys

A boiler fitness survey is a thorough examination of the boiler and related equipment to ascertain the condition of the material. It is initiated by a close visual examination to identify areas where a more exacting test may be required. These additional tests may be in the form of ultrasonic metal thickness readings, radiography, or sampling for visual and/or micrographic metallurgical examination as on Exhibit 7. In addition, random sampling may be utilized for further verification. The data and observations are compiled and analyzed relative to the original design requirements and current technological developments. With detailed knowledge of the material's condition an economic evaluation can be made to determine the extent and timing of maintenance and rehabilitation programs, thus leading to predictive management of maintenance programs.

Exhibits 8, 9, 10 and 11 are photographic examples of conditions found inside boilers while completing boiler fitness surveys. Boiler fitness studies can also indicate areas where engineered upgrades are appropriate.

Managed Maintenance Concepts

A managed maintenance program is a comprehensive plan to identify maintenance life cycles on a component-by-component basis and to develop preventive maintenance programs that preclude breakdown maintenance and which can be justified economically. Managed maintenance can maintain boiler availability near original levels as shown on Exhibit 12. Managed maintenance programs take into consideration operating experiences, design arrangements, boiler fitness surveys, down time maintenance productivity, down time costs, quality control and technologic advances. The ultimate in execution is to compress all maintenance requirements into short, scheduled outages with absolute quality so that subsequent shutdowns are not required for associated repairs.

Operator and Maintenance Training

Reliability depends upon proper maintenance and proper operation. In both areas quality training is necessary in order to execute assignments properly. B&W provides video tapes for both operators and maintenance personnel, simulators for operators as shown on Exhibit 13, and diagnostic computers for the engineers. Technological advancements are developing rapidly and computer aided services are near at hand for the basic power industry.

AVAILABILITY OF NEW UNITS

In the past 20 years, the average sized unit purchased by the U.S. Utilities has increased from 225 MW in 1960 to 600 MW by 1980. The largest units installed during this period are in excess of 1300 MW and were installed in the TVA and AEP systems.

The question of the economies of scale, plant heat rate and relative availability are factors considered by each utility in determining the size of the unit required for their particular system. There has been much debate on the merits of smaller vs. larger boiler units.

It has been well documented that there is a significant savings in capital investment and in net plant heat rate as unit size is increased. (Exhibits 14, 15, and 16)[3].

By the same token, a review of NERC availability data for the ten year period 1970 through 1980 shows that plant availability falls off significantly as unit size increases. (Exhibit 17)

This exhibit is a comparison of NERC boiler availability for boilers ranging in size from 200 to in excess of 600 MW considering all fuels, all cycles and all boiler manufacturers. This data indicates a deterioration of

[3] "Coal-Fired Unit Size Selection..is Bigger Better?", Nobile, P.A. Kettler,D.J., Ebasco Services, 1980.

almost 6% in boiler availability when comparing units in the 200 MW range with those in excess of 600 MW. We believe this presentation may be misleading to those who wish to conclude that this is a size effect.

As a boiler manufacturer, we have not seen this occur when we analyze data on modern boilers. As an example, NERC data on the last ten B&W pulverized coal-fired 3500 psi units put in service since 1973 shows an average availability of 87.1% which compared favorably to the results obtained from boilers in the 200 MW range. Many units exceed this average as indicated by the excellent availability of the B&W units for American Electric Power (Exhibit 19), the largest boilers in the world.

A further analysis of availability data comparing our most recent 2400 psi drum boilers with once-thru 3500 psi boilers shows no appreciable difference in average cumulative availability as indicated on Exhibit 20.

It is our belief that a number of features included in the modern coal-fired boiler offer the potential for availability performance in excess of 92%. This level has been achieved with our late 1970's designs regardless of size or operating cycles and is attributed to the development of the reliable MPS pulverizer, advancements in furnace wall design, conservative gas side design parameters, and the success with boiler standardization.

We conclude that the modern coal-fired steam generators are capable of obtaining good availability regardless of cycle or size and that system requirements, first cost and plant efficiency, should be the criteria for determining each utility's size selection.

We have also reviewed the availability of a group of 22 pulverized coal-fired once-through boilers, 600 MW or larger, for which we have significant data. These units average size is 875 MW and total 188 years of operating experience.

Analysis of this data indicate that the five most recent units show an availability five percentage points greater than the average for all 22 units (Exhibit 21).

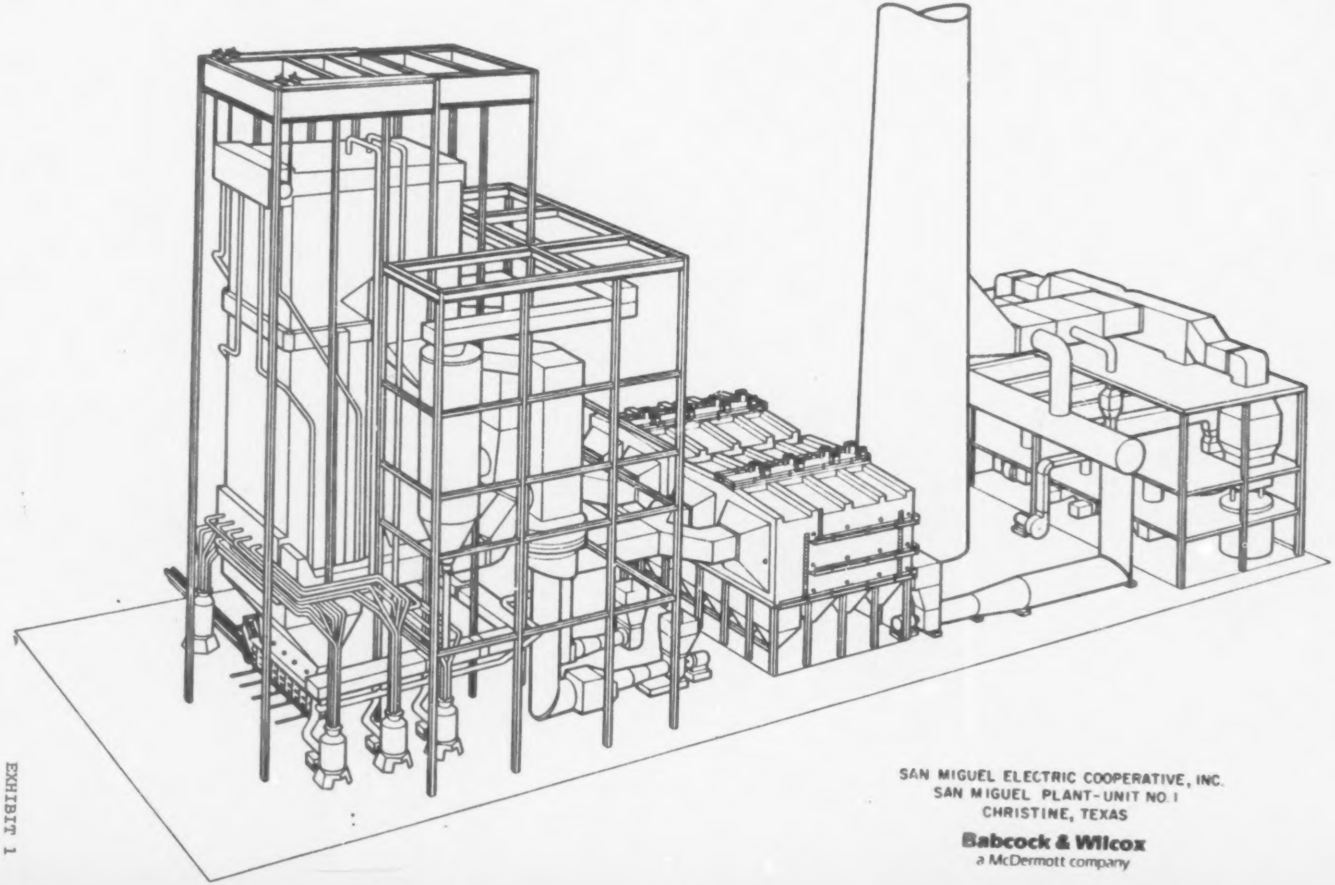
It is our opinion that part of or all of this differential could be recovered through upgrading and modification of the existing units.

AVAILABILITY TARGETS - NEW UNITS AND OLDER DESIGNS

Babcock and Wilcox believes that a target availability of 92% can be achieved on modern coal-fired boilers. This target has been achieved on many recent units through modern design practice, good operation and planned maintenance of power plant components. Since the boiler is not the only governor of plant availability, the other major components must be addressed in a systems analysis fashion in order to make a judgment on overall plant availability targets. We are performing such services as the industry desires.

As stated earlier, older units can often benefit from today's technology of design and from modern methods of inspection analysis and maintenance management. The key to improved availability of these units is the financial health of the utility industry which must be able to justify such improvements in terms of return-on-invested capital or in payback of maintenance budgets.

Thank you again for the opportunity to discuss this with you today.



SAN MIGUEL ELECTRIC COOPERATIVE, INC.
SAN MIGUEL PLANT-UNIT NO. I
CHRISTINE, TEXAS

Babcock & Wilcox
a McDermott company

EXHIBIT 1

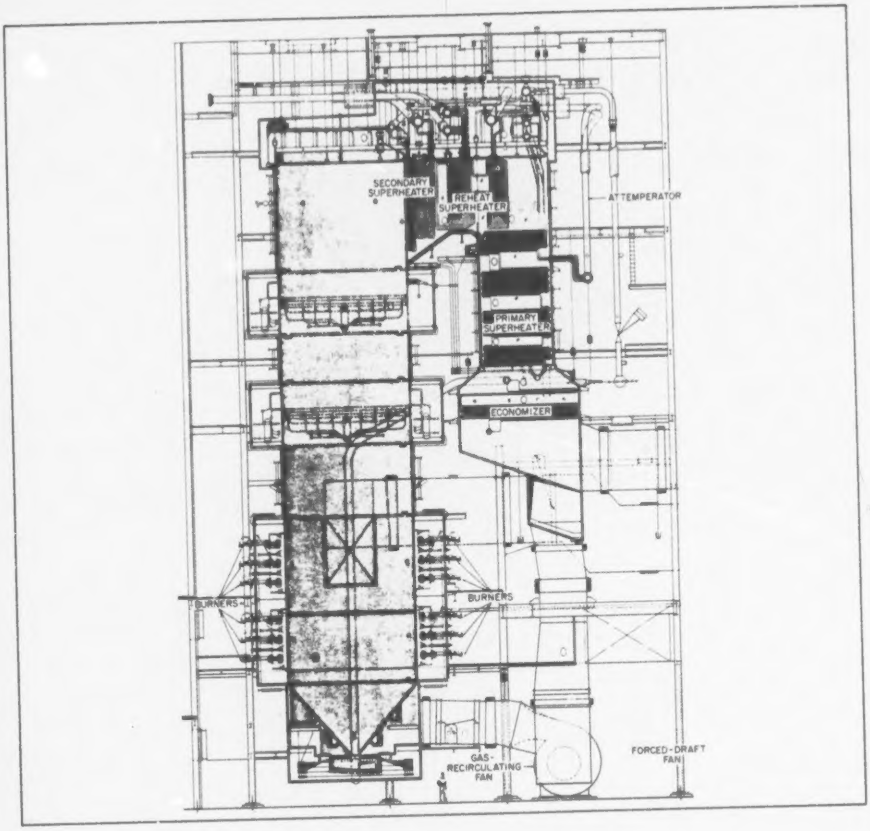
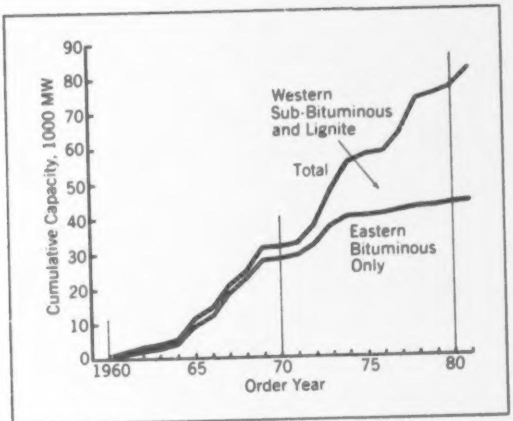
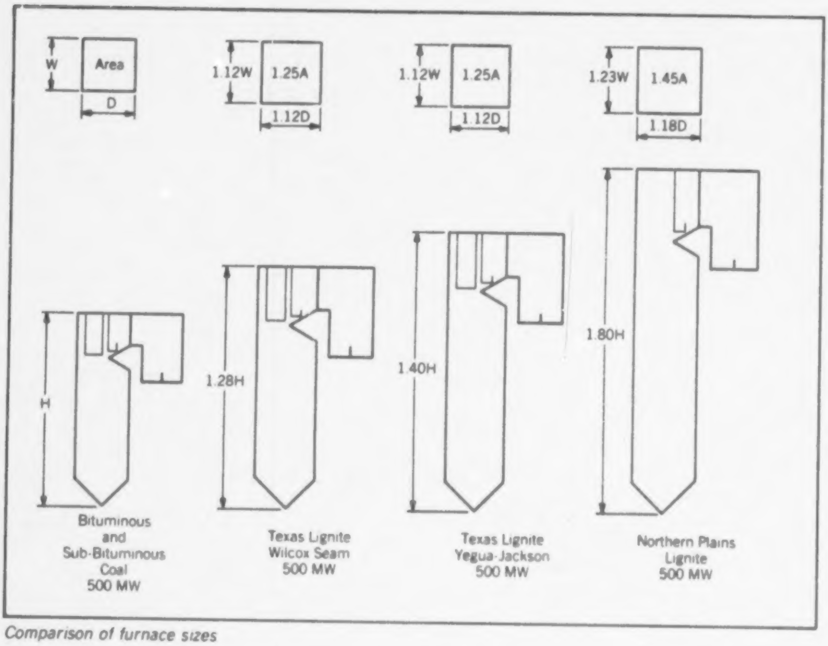

SECONDARY SUPERHEATER
REHEAT SUPERHEATER
ATTEMPERATOR
PRIMARY SUPERHEATER
ECONOMIZER
BURNERS
BURNERS
GAS-RECIRCULATING FAN
FORCED-DRAFT FAN

EXHIBIT 2



B&W pulverized coal fired boilers orders by type of coal

EXHIBIT 3


W
Area
D
1.12W
1.25A
1.12D
1.12W
1.25A
1.12D
1.23W
1.45A
1.18D
H
1.28H
1.40H
1.80H
Bituminous and Sub-Bituminous Coal 500 MW
Texas Lignite Wilcox Seam 500 MW
Texas Lignite Yegua-Jackson 500 MW
Northern Plains Lignite 500 MW

Comparison of furnace sizes

EXHIBIT 4

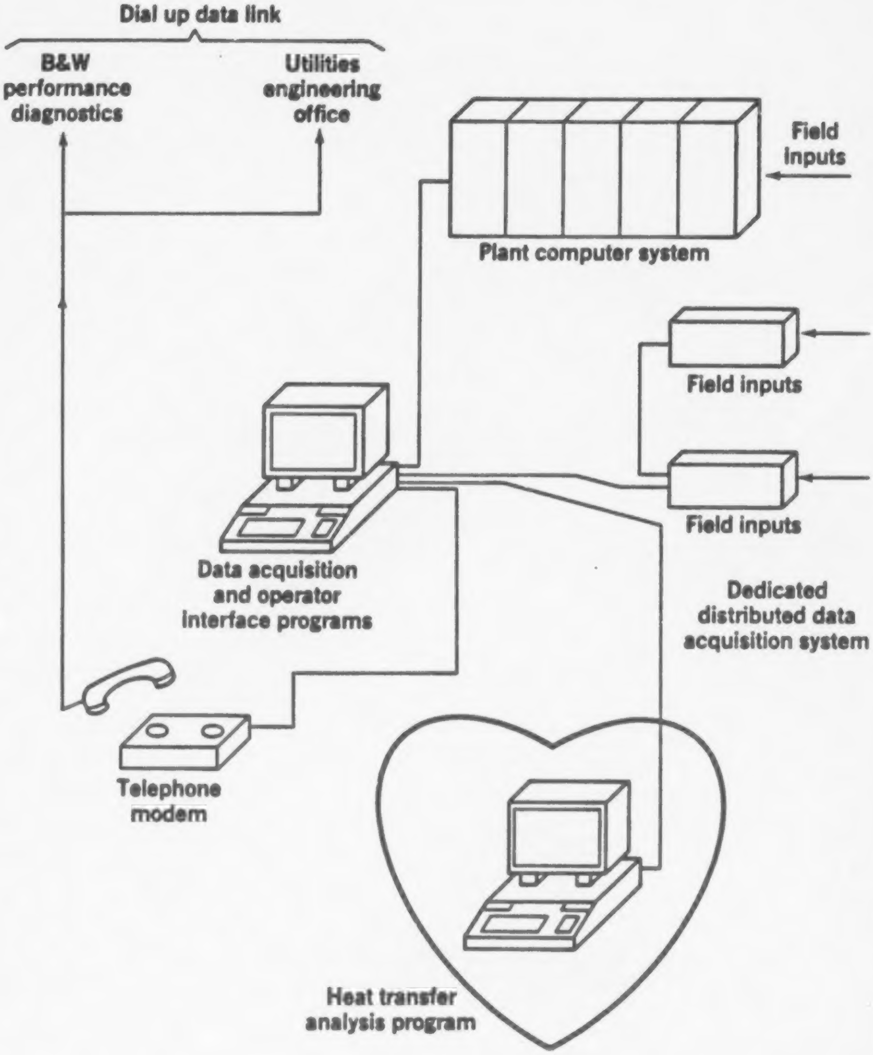
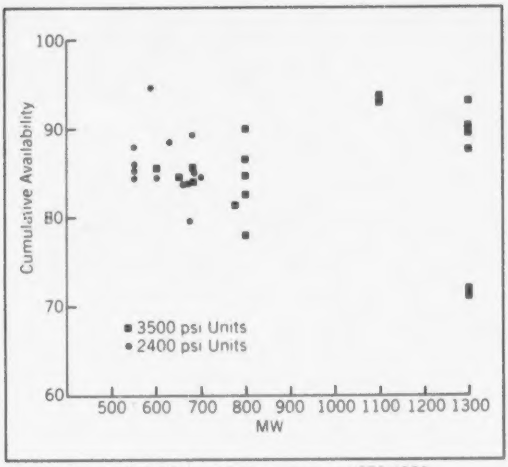
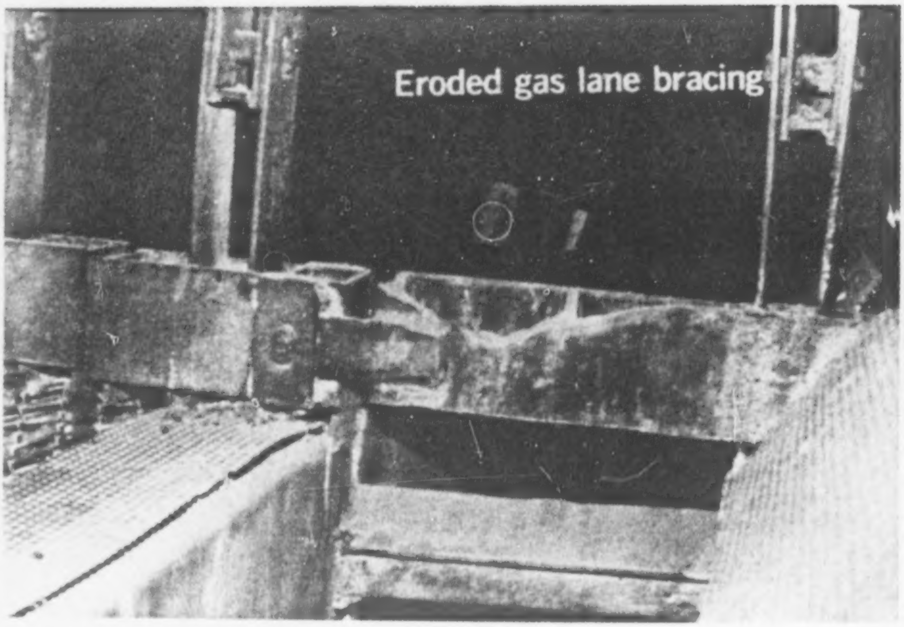

Dial up data link
B&W performance diagnostics
Utilities engineering office
Field inputs
Plant computer system
Field inputs
Field inputs
Data acquisition and operator interface programs
Dedicated distributed data acquisition system
Telephone modem
Heat transfer analysis program

EXHIBIT 5



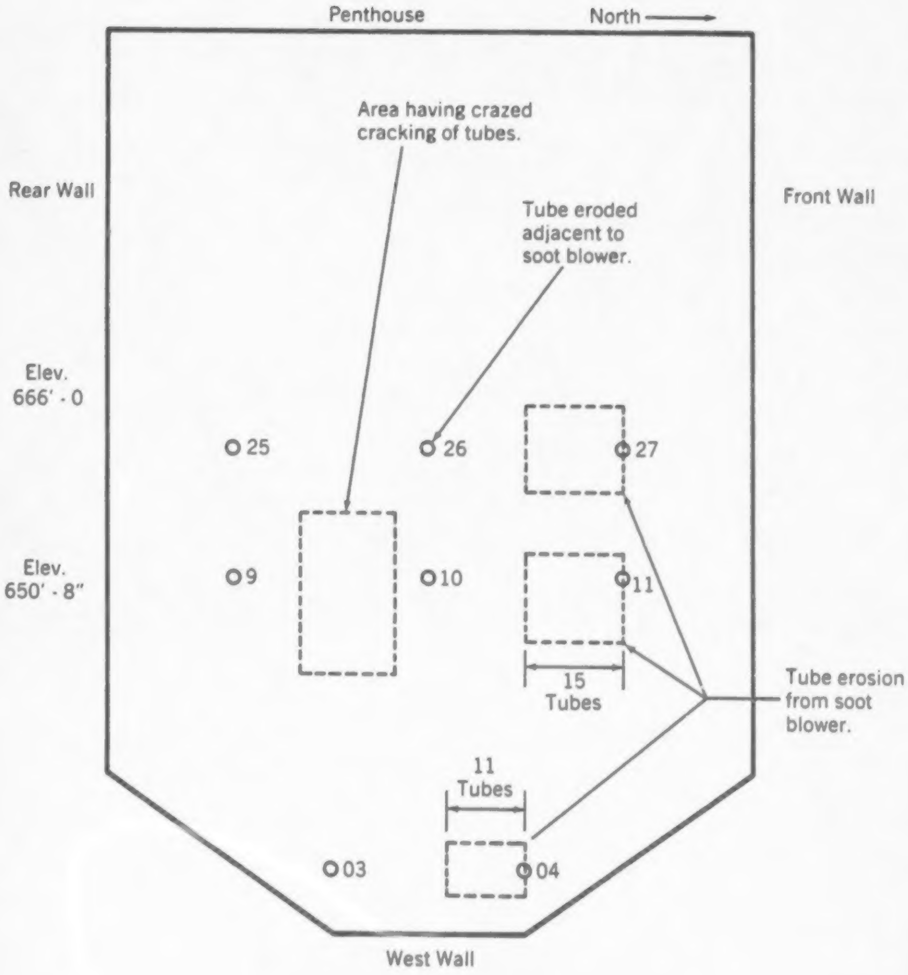
Availability of B&W PC fired boilers start up 1970-1980

EXHIBIT 6



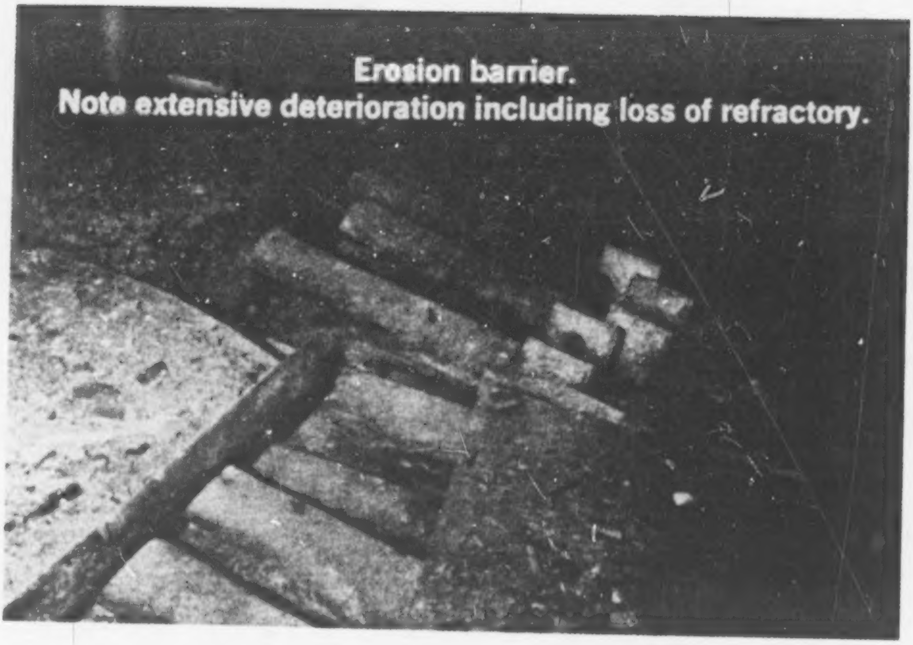
Eroded gas lane bracing

EXHIBIT 7


Penthouse
North
Area having crazed cracking of tubes.
Rear Wall
Tube eroded adjacent to soot blower.
Front Wall
Elev. 666' - 0
25
26
27
Elev. 650' - 8"
9
10
11
15 Tubes
Tube erosion from soot blower.
11 Tubes
03
04
West Wall

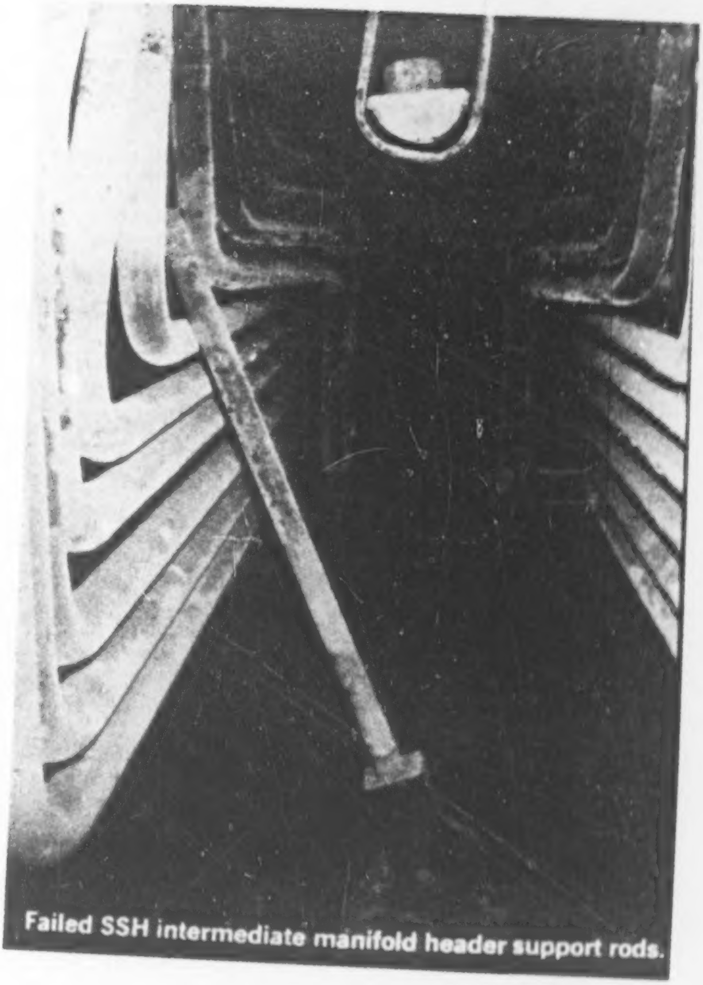
Areas of concern on the west wall

EXHIBIT 8



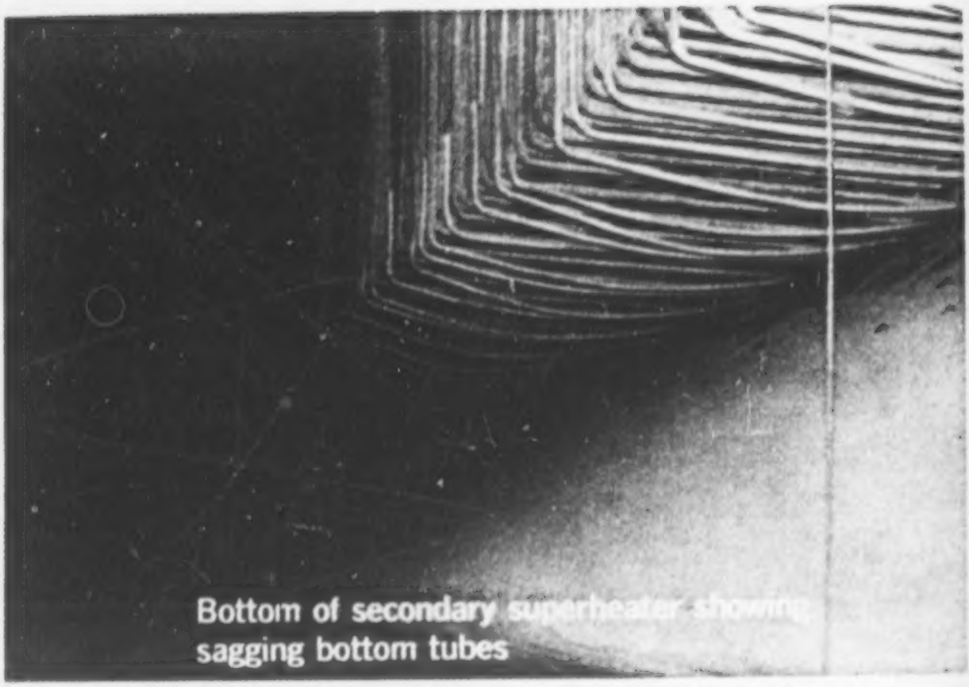
Erosion barrier.
Note extensive deterioration including loss of refractory.

EXHIBIT 9



Failed SSH intermediate manifold header support rods.

EXHIBIT 10



Bottom of secondary superheater showing sagging bottom tubes

EXHIBIT 1

Extended service programs

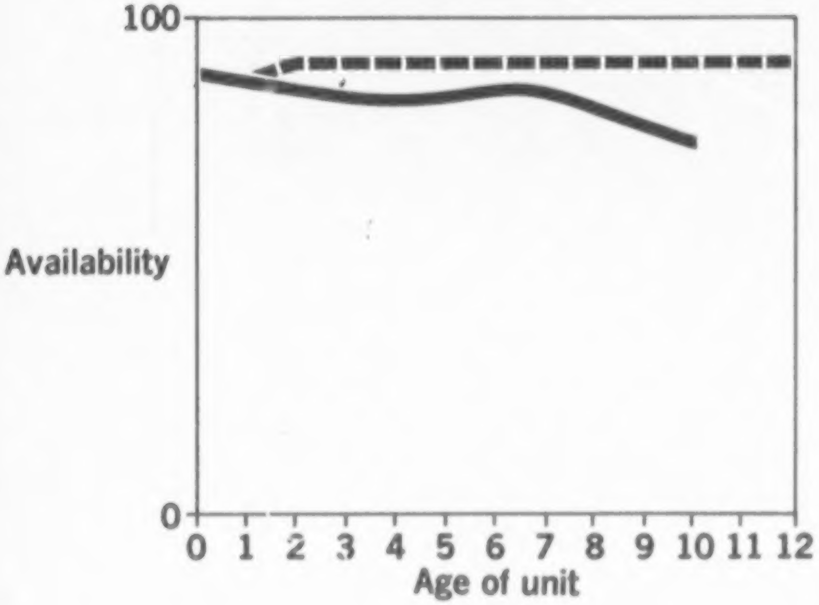


EXHIBIT 12

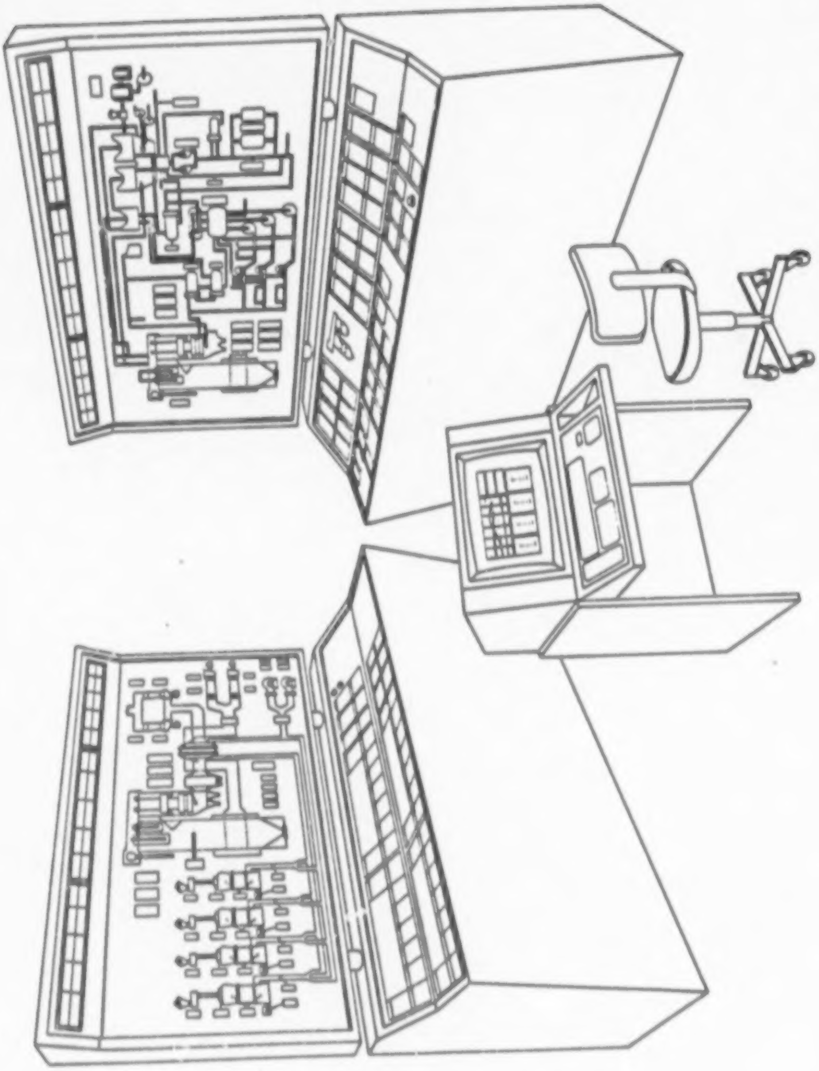
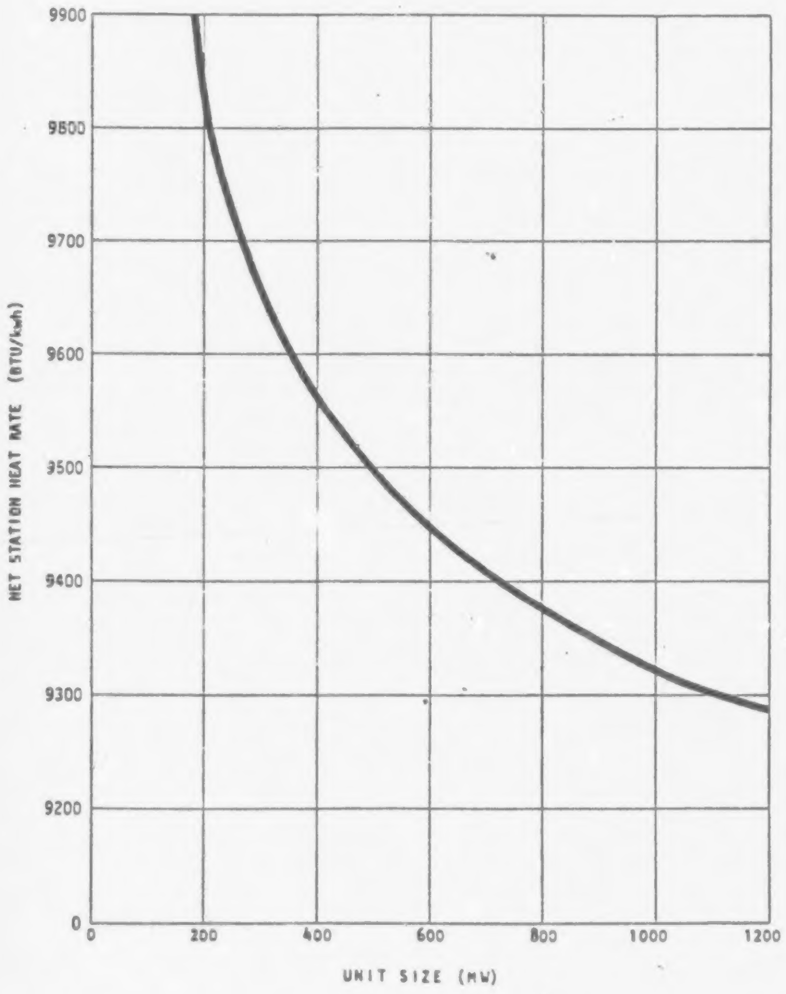
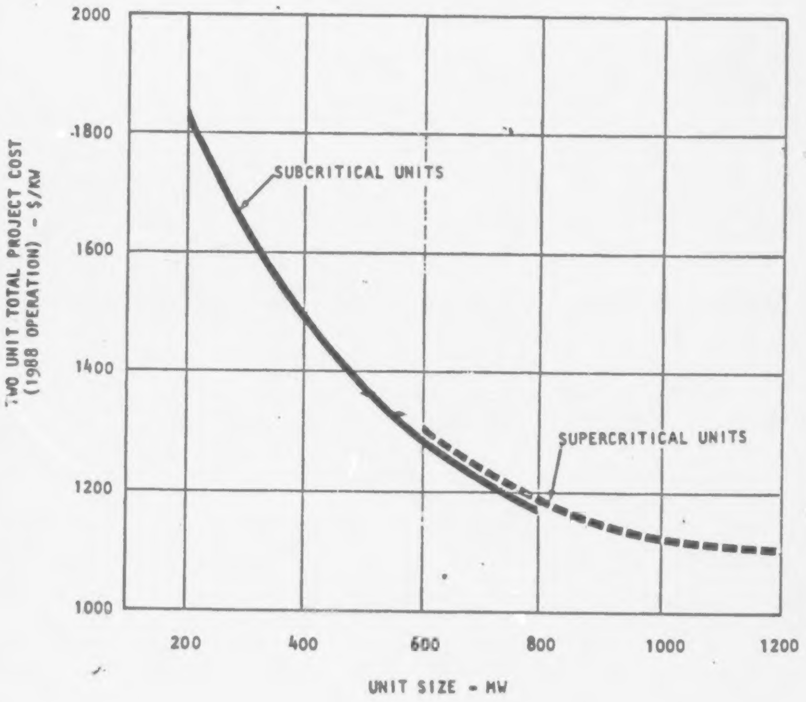


EXHIBIT 13



NET STATION HEAT RATE VERSUS UNIT SIZE

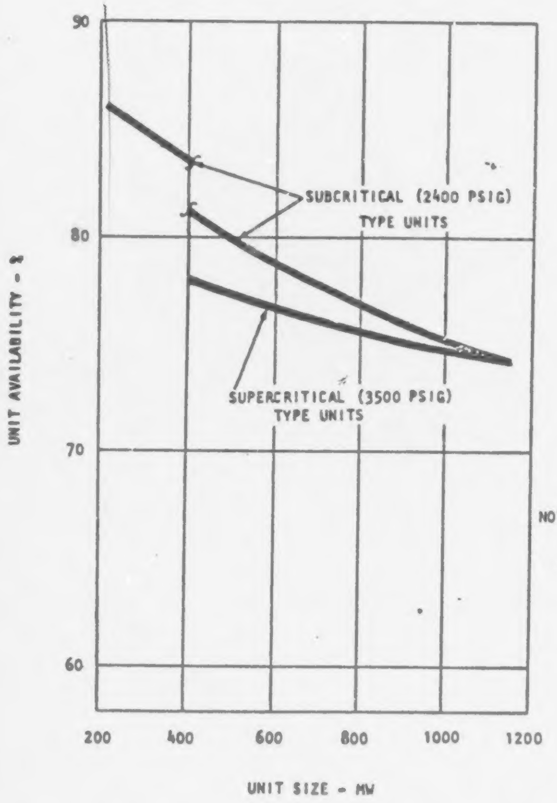
EXHIBIT 14



INVESTMENT COST ($/KW IN 1988)
VERSUS UNIT SIZE

EXHIBIT 15

UNIT AVAILABILITY VERSUS UNIT SIZE



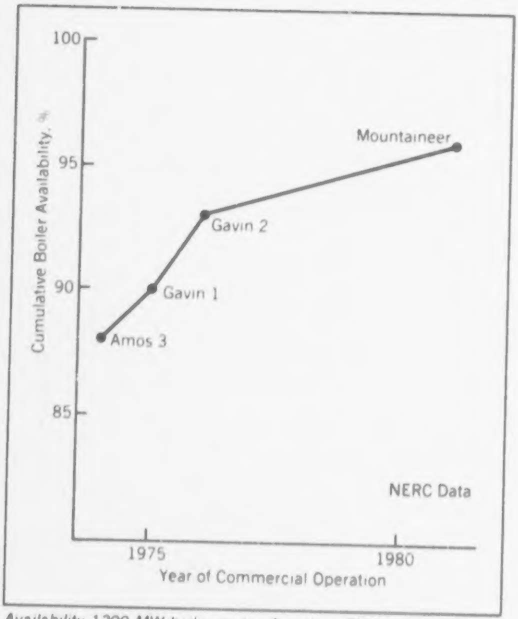
NOTE: AVAILABILITY IS THE PER CENT TIME REMAINING AFTER SUBTRACTING FORCED OUTAGE AND MAINTENANCE TIMES.

EXHIBIT 16

NERC Boiler Availability Data
1971 through 1980

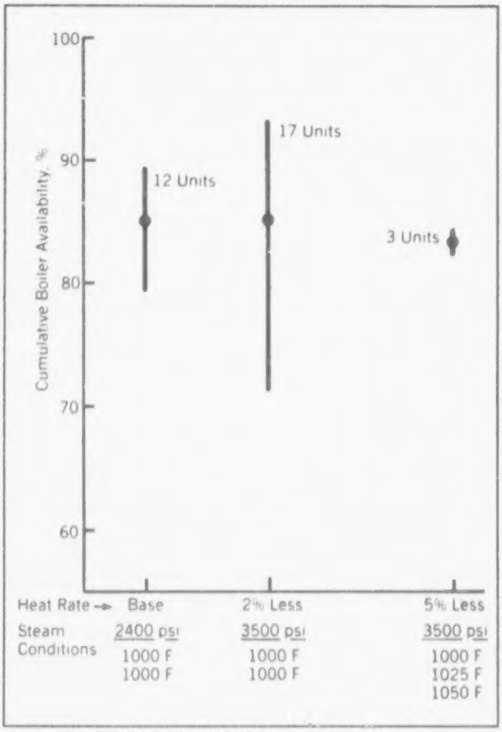
Size	Availability %
200-299	87.2
300-399	84.6
400-599	84.8
600-799	83.3
600 & above	81.5
Last 10 B&W once through PC-fired boilers 600 to 1300 MW (early 70's operation)	87.1
Late 70's operation	>92

EXHIBIT 17



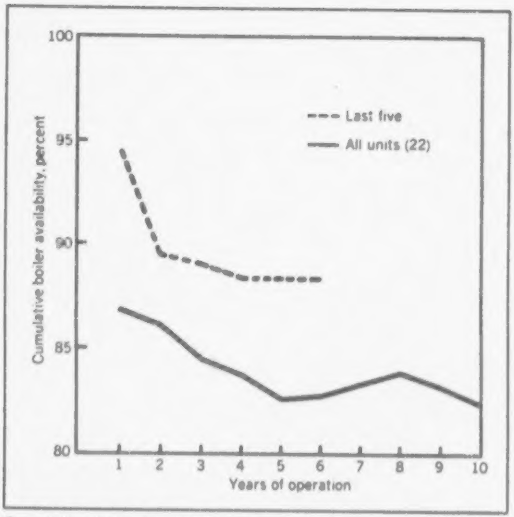
Availability 1300 MW boiler series American Electric Power

EXHIBIT 18



Availability of B&W PC fired boilers comparison by cycle conditions

EXHIBIT 19



Cumulative boiler availability for pulverized-coal-fired 3500 psi boilers, 600 MW and larger

EXHIBIT 20

Mr. Fuqua. Thank you, Mr. Smith.

Dr. Pate, I was just looking at your testimony. You say that INPO is funded by all the members that have nuclear powerplants.

Dr. Pate. Yes, sir.

Mr. Fuqua. Is there any DOE money involved, or do you receive grants from DOE to perform certain safety studies or other things for DOE or NRC?

Dr. Pate. DOE has funded selected specific activities. For example, the manpower survey of the industry was done with DOE funds, and DOE has funded a major portion of initial efforts at the job and task analysis work managed by INPO. The purpose of job and task analysis is to accurately determine the training needed by all types of plant operating and maintenance personnel.

Mr. Fuqua. You discussed the importance of stimulating management to insure the effectiveness of your program. What level of utility management gets involved in the plant evaluation?

Dr. Pate. During the station evaluations, the plant manager is involved on a day-to-day basis with the team manager for the INPO evaluation team. At the exit meeting in which we review the results of the evaluation, typically the utility chief executive officer or the president of the company attends, as well as the senior nuclear vice president.

For the first round of INPO evaluations, 50 operating stations in all, the president of INPO attended each one personally. I think that is an indication of his commitment to involvement by top management, and top management in the industry has responded and has demonstrated a great deal of interest in what INPO is finding and in how they can improve their plants.

Mr. Fuqua. Maybe you could elaborate on what the nuclear industry is doing to insure the quality of the plants under construction. I am particularly concerned, when we have events that happen such as at Diablo Canyon plant, where apparently there was an integration of some of the systems. If my memory serves me correctly, that caused some problems that have prevented it from startup. I am not speaking of just that plant, but that is an example.

Dr. Pate. Yes, sir. In February of this year the industry, in what I would call a concerted and coordinated effort, asked INPO to undertake a substantial program to look at plants under construction. The first phase of the program calls for development of criteria followed by a series of pilot evluations. Workshops will then be held with the industry utilities that are building plants, and then a self-initiated evaluation, using the criteria developed by INPO and proven in the pilots, will be conducted for each construction site, except for those that are essentially complete.

We have already put a lot of effort into that. That program is on schedule. We are in the middle of our second pilot evaluation of a utility plant under construction at the present time.

Mr. Fuqua. Do you see yourself getting continually more involved in that?

Dr. Pate. The plan calls for the utility industry, in concert with INPO, to assess what kind of resources are required and what kind of results we think could be achieved by a continuing INPO involvement, as we learn through this first phase. I expect that decision will be made late this summer by INPO's board of directors, in consultation with all affected utilities.

Mr. FUQUA. There has been a great deal of discussion about standardized plant design. Do you see this as being practical and also as contributing to reliability?

Dr. PATE. Included in my written testimony is INPO's involvement in an international program, and as a result of interest shown by a number of foreign countries we have had considerable interaction, including some exchange visits with France and Canada, and our people are very impressed by the standardization the French and Canadians have undertaken in their plant design, construction and operation. That clearly has benefits in the opinion of our people who have looked and in my personal opinion.

Mr. FUQUA. You think that would contribute to increased reliability?

Dr. PATE. Absolutely; yes, sir.

I also come from a Navy background. We had a great deal of standardization in nuclear submarine plant designs, construction, and in our methods of operation, and the benefits of that are enormous.

That is not to say that every plant should be the same, but groups of plants, or major sections of plants, that are standard, sir, would be the ideal.

Mr. FUQUA. I agree.

Let me also commend you for what you are doing in the control room design. In your prepared satement you have alluded to that. It has been my observation in visiting a lot of nuclear powerplants that many of them in the early days were carryovers in the control room from the old coal-fired plants, and they have certainly not, I believe, kept up with standards that there should be. This is one of the recommendations that this committee made after the TMI accident. Control rooms are the heart of the operation and very important. How do you design that so that you keep the attention of the operators and also, similar to what you have done in the Navy and we have been able to do in other types of highly sophisticated control, such as in the space program and others where it is very important that the operators have the capacity and the attention to do it, rather than in some bland room that many of them were designed to be in the early days. I would certainly like to commend you for that. I think there is a lot of improvemement to be made.

Dr. PATE. Thank you, sir. I listened carefully to every word you said, and I agree with of it. I appreciate the compliment and your interest in our work.

Mr. FUQUA. Thank you.

Dr. Patton, is it possible to significantly increase the reliability of the transmission and distribution system with current design technology, or is there more R&D required to bring forth advances in hardware and communications and control?

Dr. PATTON. I would say that it is going to be expensive to significantly improve the reliability performance of distribution, if we can start at that end. Probably the things that are most effective in improving reliability would simply be improving the reliability performance of individual components through better maintenance and the like—tree trimming is an obvious example.

Whenever the utilities get in a bind, they say, "Well, can we avoid trimming the trees this year," and the like. At the distribution level that is critical.

I find that in talking to utility commissions they are very concerned about the response time. They are not so concerned about how often they fail, but, "How long are we out when we are out?"

Likewise, utilities can impact that simply by dispatching the crews better, having them more efficiently located in the service territory, having more crews, and the like.

But improving reliability at the distribution level, aside from some activities like that, is likely to be fairly expensive. There certainly are things that are going on today with regard to distribution automation and the like which may have some impact on that, but I happen to think that that is not likely to have a large impact on reliability performance—maybe some; I would not doubt that, but I am not so sure that it is going to have a large impact.

At the transmission level, I think that there needs to be better attention paid to relaying practices, because virtually all transmission shutdowns and in fact large-scale system collapses can be traced ultimately to protection or relaying problems of some sort.

So to me that suggests that a more disciplined, careful analysis of possible problems in connection with relaying might be the most cost-effective way to make transmission more reliable. I doubt that just building a few more lines here and there is going to make it significantly more reliable. It will improve things, but it will not escape the major collapses, which I think are a prime concern to us all. We heard Mr. Brown speak about that earlier on.

With regard to our methods of analysis, our methods of analysis are not going to make the system more reliable. It may help us make intelligent choices between competing alternatives.

Mr. FUQUA. Mr. Smith mentioned that. I think maybe you were just talking about boilers, but the breakdown—when it breaks down, that is when you fix it. "If it ain't broke, don't fix it," I guess is the general phrase we use around here sometimes.

Dr. Patton, is there any method that utilities use for planning for replacement of components?

Dr. PATTON. Yes. Utilities, by their experience, arrive at certain maintenance schedules, and there has been considerable interest in the IEEE—the Institute of Electronics Engineers—and in other utilities circles, to try to identify problems early on, so that the proper corrective maintenance and remedial measures may be taken before widespread problems occur.

But the identification of problems early is a difficult exercise from a statistical point of view, and yet certainly we would like to do that.

I have often wanted to be able to take a utility generator, or a group of utility generators, and operate them under some alternative maintenance practices and see how they do, but hardly anybody wants you to do that, you know.

Mr. FUQUA. Is it the cost involved?

Dr. PATTON. It is simply that no one is going to jeopardize their extremely heavy investment to let you experiment to see how things go. So the upshot of that is that you have to try to infer things from field experience, which is corrupted by all sorts of other things that have gone on.

So everybody would like to arrive at some kind of optimal maintenance schedule—yes. Now, what is it? That is the big argument. I do not think anybody knows at this point.

Mr. **FUQUA**. Is there basically a lifespan for certain switches and other—I am not speaking necessarily of the generating equipment—motors and other things that must be in operation—but I am thinking also along the distribution line—transformers and things of that type that have generally a life expectancy, do they not?

Dr. **PATTON**. Yes, but it is very much a function of how they operate and the duty cycle in which they find themselves. You can burn a transformer out really quickly if you overload it. On the other hand, if you treat it properly, it may last 30 years, and remain in service until it becomes obsolete for some reason.

Much utility equipment is essentially capable of indefinite use as long as it is operated within conservative operating bounds and as long as preventive maintenance is carried out. There is really no reason to throw anything away until it is just no longer economically useful to you.

Mr. **FUQUA**. Mr. Smith, recognizing that contracts are generally awarded simply on the basis of the lowest bidder in most cases, what incentives exist for manufacturers to spend funds on R&D to increase product reliability, which may have to be recovered through higher prices?

Mr. **SMITH**. I believe that question may have a couple of different sides to it. Because of the very low growth of the electric utility industry this year, we probably will not see the level of orders equal to what it was back in the late 1930's, and this is really significant as a problem to the manufacturers who are in this business.

The healthy manufacturers, though, have a large backlog of operating units, and the incentive to put research funds into this type of technology for B&W is to support the extension of the operation of these older units until such point in time that the utility industry regains its financial health and we go back to a reasonable load growth scenario.

So I think there is incentive for us anyway to put money into R&D, and we are working very closely with the Electric Power Research Institute on programs in the availability-reliability area for fossil units.

Mr. **FUQUA**. Taking a primary piece of equipment—say an induced-draft fan—how does the reliability of that today compare to, say, 15 years ago, with new materials and other things coming along? Are we making improvements?

Mr. **SMITH**. There has been a lot of development of technology in the fossil industry in the past 10 years. For example, the types of fan equipment which are used today in most of the new plants are completely different in design than the ones that were used back in the late 1960's and early 1970's.

Also, the utilities and architect engineers and manufacturers have put more conservatism in the design of the fans. In other words, where we used to design a fan so that at its maximum load it would just barely pump enough air through the unit, today we put a significant safety margin of up to 40 percent on. So there is that double effect of a newer design and more conservative application of the design.

Mr. Fuqua. Thank you very much for being here today. We appreciate your taking the time. I think it has been very, very helpful to us. I thank you all for being here today.

The meeting will adjourn.

[Whereupon, at 12:05 p.m., the hearing was recessed, to reconvene at the call of the Chair.]

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